OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **January 6, 2014**

TO: Phillip Fielder, P.E., Permits & Engineering Group Manager

THROUGH: Phil Martin, P.E., Manager, Existing Source Permits Section

THROUGH: Peer Review

FROM: David Schutz, P.E., New Source Permits Section

SUBJECT: Evaluation of Permit Application No. **2007-026-C (M-5)(PSD)**
Wynnewood Refining Company, LLC
Wynnewood Refinery
Hydrocracker Restoration and New Hydrogen Plant
Wynnewood, Garvin County, Oklahoma
906 S. Powell
Located Immediately South of Wynnewood on US-77
Latitude 34.6325°N, Longitude 97.1639°W

SECTION I. INTRODUCTION

The Wynnewood Refining Corporation LLC (WRC) has requested a construction permit for proposed modifications to their petroleum refinery. Wynnewood Refining Company operates a petroleum refinery (SIC 2911 & NAICS 324110) in south-central Oklahoma. The facility is currently operating under Permit No. 2007-026-TVR (M-4) which was issued on May 21, 2013.

The application proposes to restore the Hydrocracker Unit to its original design service by replacing the hydrotreating catalyst with by a hydrocracking catalyst. Restoring the Hydrocracker Unit to its original design service will allow the production of heavier distillate products (i.e., diesel fuel). The restored unit will require additional hydrogen, and an “off the shelf” hydrogen plant will be installed to provide the additional hydrogen. The primary air emissions components are:

- A new 126 MMBTUH heater will be added as Point “REFORMER” in EUG-37. The unit will be fueled with refinery fuel gas or natural gas. The only refinery fuel gas combusted in the unit will be recycle tailgas from the Pressure Swing Adsorption process within the hydrogen plant, which is inherently low in sulfur.
- Process drains in the unit will be added as “EU-53WW” in EUG-60.

- A steam deaerator vent, Pressure Swing Absorption hydrogen vent, and a reformer blowdown vent will be added to EUG-93, “Miscellaneous Insignificant Process Vents.” (Note: since all vents are located downstream of reactors which produce hydrogen from methane and steam, there will be little VOC/HAPs in the streams to be discharged.)
- Some valves and flanges will be added to the list of fugitive VOC leakage in EU-3725A.

There will be increased utilization of process flares and diesel storage. The project will result in approximately 3,000 BPD additional diesel being produced. The increased diesel production was accounted for by increasing throughput limits for T-200 in EUG-7. Expected maximum increases in flare utilization and resultant emissions have been quantified in Section IV.

The process streams will be pipeline-grade natural gas (from which most VOC has been removed), steam, and hydrogen. Fugitive leakage from valves, flanges, etc., is expected to be negligible. Since the unit will create more steam than it consumes (from waste heat recovery), there will be no additional demand on existing boilers.

The proposed project is subject to PSD review for adding greenhouse gas emissions (CO_2e) above the PSD levels of significance. As a physical change with a “significant” modification, a Tier II construction permit is required.

SECTION II. FACILITY DESCRIPTION

The refinery converts crude oil into a variety of liquid fuels, solvents, asphalt and liquefied petroleum gases (LPG). Operations at the facility are divided into four categories: storage tanks, process units, utilities and auxiliaries, and blending and loading. The facility includes 27 process units for distillation and chemical reaction operations, 78 significant atmospheric storage, 51 combustion units, additional combustion units operated for controlling air pollution emissions, fuel gas amine treating and regeneration units, sulfur recovery and tail gas treatment units, product and raw material loading/unloading units, gasoline blending, diesel blending, asphalt blending, and auxiliary units for waste handling. The current facility capacity is 74,000 barrels per day crude oil input. Crude oil arrives primarily by pipeline but also by truck and rail.

A. Process Units

There are 27 processing operations identified by the Wynnewood Refinery process flow diagram. (The Benfree Unit will be a 28th process unit when construction is completed.) These operations include the No. 1 Crude Unit, No. 3 Vacuum Unit, No. 2 Crude Unit, No. 2 Vacuum Unit, Straight Run Stabilizer, Merox Unit, No. 1 Splitter, No. 2 Splitter, Naphtha Unifiner, Hydrogen Plant, Hysomer Unit, ROSE (Residual Oil Supercritical Extraction) Unit, CCR (Continuous Catalyst Regeneration) Platformer, Hydrocracker, Fluid Catalytic Cracking Unit, Platformer Depropanizer, Deisobutanizer, Olefins Treater, Propylene Splitter, Alkylation Unit, Fuel Gas Treaters, Fuel Gas Drum, Sulfur Recovery Unit, Diesel Hydrotreater, Asphalt Oxidizer, Asphalt Blending, Distillate Blending, GHDS Unit, and Gasoline Blending. The refinery also operates gasoline, distillate, asphalt, LPG (liquefied petroleum gas), solvent, and slurry loading facilities and steam and utility systems.

Crude oil processing begins at the No. 1 and No. 2 Crude Units. First, salt, water, and inorganic particles are separated from the crude oil, which is then distilled. In the distillation process, the crude is divided into several fractions depending on boiling point of the hydrocarbons present. Streams from the Crude Units include light hydrocarbons (methane, ethane, propane, butane) that become refinery fuel gas and liquefied petroleum gas (LPG), straight run gasoline, naphtha, distillate, and residual streams such as gas oil and reduced crude. The residual oil, referred to as "reduced crude," is first processed in the Crude Vacuum Units (CVU) where additional gas oil is distilled out at reduced pressures. The gas oil from the crude units and vacuum units becomes the primary feed to the Fluid Catalytic Cracking Unit (FCCU). As an intermediate step, some of the vacuum bottoms are processed for removal of asphaltenes/resins in the ROSE (Residual Oil Supercritical Extraction) Unit before proceeding to either the Asphalt Oxidizer or FCCU.

The FCCU heats residual hydrocarbons to 900-1,000^{o}F in the presence of a silica-based catalyst to convert the "gas oil" into lighter components. The large organic molecules break into smaller components. Most of these lighter components (about 60%) are recovered for gasoline blending. Other lighter components are recovered as reactants for other refinery processes, fuel gas, olefins, or LPG. Heavy oil off the bottom of the unit is sold as slurry oil. Some of the organic materials become "coke" on the surface of the catalyst that is regenerated by burning off the coke before re-circulating the catalyst back to the FCCU.

Some of the light naphtha is processed by the "CCR Platformer Unit." "CCR Platformer" is a shortened form of "continuous catalyst regeneration platinum-catalyzed reformer" which converts naphtha into aromatic components of gasoline such as benzene, ethyl benzene, toluene, and xylene.

Other gasoline blending components are prepared by combining smaller organic components in the LPG range into heavier components in the Alkylation Unit. Olefins separated from the processes (mostly as products of the FCCU) are reacted in the presence of hydrogen fluoride (HF) to form larger heptane and octane molecules.

Sulfur must be removed from sour refinery fuel gas, blending components, and reactants which will become blending components. WRC treats refinery fuel gas for H_2S removal by amine treatment. The sour gas from regenerating the amine is then processed in a sulfur recovery unit (SRU) that converts H_2S to molten sulfur. The SRU is also used to treat off-gas from sour water stripping for H_2S and ammonia removal. Some distillates are processed by a "Merox" unit, in which high-strength sodium hydroxide reacts with mercaptans and converts them to disulfide oils which remain in the product. Light naphtha is treated in a "Unifiner" Unit. "Unifining" is equivalent to hydrodesulfurization, where hydrogen gas is used to react with hydrocarbons, breaking off sulfur as hydrogen sulfide and lesser amounts of other Total Reduced Sulfur (TRS) compounds such as methyl sulfide. Hydrotreating also converts larger olefins into aliphatic hydrocarbons and naphthas which are not prone to form gummy resins during storage. An amine unit is also used to reduce the H_2S content in alkylate feed. The H_2S-containing gas from treating alkylate feed can be burned in the Aklylation Unit's depropanizer reboiler (Heater 5H1, a "grandfathered" unit) or processed through the SRU.

Hydrotreating requires large amounts of hydrogen gas to be created. Most of the hydrogen is created by “steam reforming.” Here, steam is mixed with hydrocarbons such as methane in a reaction such as $CH_4 + 2H_2O \rightarrow 4H_2 + CO_2$. This reaction is conducted in the new Diesel Hydrodesulfurization Unit and proposed Hydrogen Plant Reformer. The Platformer Unit also creates a large amount of hydrogen gas. Unreacted hydrogen gas is vented from other units into the Refinery Fuel Gas (RFG) system.

In addition, this refinery includes a “Hysomer Unit.” This unit is commonly referred to as an “Isomerization Unit,” which changes the molecular structure of organic compounds into ones more favorable to gasoline blending. This refinery also operates a hydrocracker. Similar to the FCCU, this unit cracks larger molecules into ones in the size range for gasoline blending.

For compliance purposes, the facility has reorganized the process units into 12 process unit areas that also include associated tankage. This is allowed by 40 CFR Part 63, Subpart CC.

B. Storage Tanks

There are currently 105 significant hydrocarbon storage tanks at the refinery. Of these, 27 are pressure vessels operated with only fugitive emissions. The other 78 are operated at atmospheric pressure. In addition to the significant hydrocarbon tanks, the refinery has numerous insignificant tanks, acid tanks, caustic tanks, chemical additive tanks, wastewater tanks, and fire water tanks.

There are several rules and regulations affecting storage tanks, depending on liquid stored, capacity, vapor pressure, hazardous air pollutant (HAP) concentrations, and date of construction/reconstruction. The tanks’ designs are internal floating roof, external floating roof, vertical cone roof, and horizontal.

These tanks include raw material storage, product storage, and storage for intermediates. Having intermediate storage allows various process units to keep operating when upstream or downstream units are down or operating at reduced capacity. The presence of intermediate storage allows for delineation between process units as necessitated by NSPS Subpart GGG and 40 CFR Part 63, Subpart CC.

C. Utility Operations

Utility operations provide fuel and steam to heat various operations, and allow for discharge of waste.

Refinery fuel gas is a blend of natural gas, non-condensable gases, gases from relief valve discharge, unit purges, and a variety of process unit off-gases. A wide spectrum of gases generated in the refinery which are combustible become refinery fuel gas. These gases are combined in a single fuel mix drum for supply to all units within the refinery. Ideally, the refinery would generate the same amount of fuel gas as is needed, but in reality, fluctuations result in purchasing natural gas on some days and in flaring excess fuel gas on other days. The fuel gas heating value has ranged from 684 BTU/SCF in 2000 to 1,244 BTU/SCF in 2006.

The mix drum blends three streams, “sweet” gases from the platformer, “sour” gases from other units, and pipeline-grade natural gas. Sour fuel gas is treated with amine to remove H_2S. Because “grandfathered” units are limited to a maximum of 450 ppm sulfur, WRC has the option of treating some of the fuel gas to less than 450 ppm sulfur and, for NSPS sources, some to less than 160 ppm. A continuous emissions monitoring system (CEMS) is used to demonstrate compliance.

There are currently four boilers at the facility. These boilers were designated “Wabash Boiler,” “Indeck Boiler,” “Nebraska Boiler,” and “Holman Boiler.” The fate of the Wickes boiler which recently exploded has not yet been determined.

Three flares are currently present at the facility. The South Flare burns releases from relief systems and vents in the Crude Units, Crude Vacuum Units, Hysomer Unit, No. 1 Naphtha Splitter, No. 2 Naphtha Splitter, Merox treater, Refinery Fuel Gas (RFG) Unit, and miscellaneous units located at the south end of the facility. The south Hydrocracker flare burns releases from relief systems in the Hydrocracker Unit. The West Flare burns releases from the Naphtha Unifiner Unit, CCR Platformer, FCCU, Deisobutanizer Unit, Plat Depropanizer Unit, Alkylation Unit, LPG loading rack, and pressure tanks for propane, butane, and olefins.

Wastewater is collected throughout the refinery. The most significant source is the crude oil desalters, where oily water is separated from crude oil. Various units generate additional wastewater with varying degrees of oil content. The refinery segregates stormwater that falls outside the process areas into a separate wastewater system that discharges through a permitted stormwater outfall. Stormwater that falls in process areas is not collected in separate sewers, but some units do preliminary oil-water separation prior to discharging into integrated sewers. There is an initial oil-water separator adjacent to the Crude Desalter and another one adjacent to the Crude Unit, Hydrocracker, and Platformer. Oily water proceeds to an API separator, then to an Activated Sludge unit. Sludge is periodically collected and dewatered for shipment off-site, while water continues to clarifiers and lagoons, and eventually to the Washita River.

D. Blending and Product Loading Operations

Equipment is present for shipping or receiving several hydrocarbon products: LPG, gas oil, asphalt, propylene, isobutane, n-butane, gasoline, jet fuel (JP-5 and JP-8), slurry, solvent, burner fuel, and diesel. LPG, gas oil, propylene, and butanes are both bought and sold by the refinery, depending on market conditions, short-terms excesses, etc. Molten sulfur is also loaded into rail cars or trucks.

Gasoline blending is done on a batch basis using large tanks. The several components are measured into the tanks. The tanks perform dual roles, both as process equipment and storage equipment.

Gasoline products are sold by either pipeline or truck. The truck loading rack is equipped with a vapor recovery unit to recover the hydrocarbon vapors displaced out of the mobile tanks as they are loaded.

SECTION III. EQUIPMENT

The contents identified in the following tables concerning tanks are typical. Tank contents will vary from time-to-time depending upon refinery requirements, but will be limited by the suitability of a particular tank for a particular hydrocarbon.

EUG 1 – Cone Roof Tanks, Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	Capacity	Installed Date
P-T108	P-T108	Jet kerosene	13,800 bbl.	1945
P-T111	P-T111	Jet kerosene	5,000 bbl.	1945
P-T162	P-T162	JP-8 additive	1,000 bbl.	1954
P-T252	P-T252	Slurry oil	26,800 bbl.	1945
P-T253	P-T253	High-sulfur diesel	25,000 bbl.	1957
P-T256	P-T256	Jet kerosene	5,000 bbl.	1957
P-T260	P-T260	Slurry oil	5,100 bbl.	1957
P-T262	P-T262	Gas oil	5,100 bbl.	1959
P-T-263	P-T263	Slop oil	5,100 bbl.	1959
P-T1441	P-T1441	Jet kerosene	34,800 bbl.	6/72
P-T1472	P-T1472	Low-sulfur diesel	34,700 bbl.	6/73
P-T2052	P-T2052	Slop oil	1,000 bbl.	1945
P-T101	P-T101	Asphalt	64,000 bbl.	1945
P-T107	P-T107	Asphalt	78,000 bbl.	1945
P-T120	P-T120	Asphalt	2,800 bbl.	1945
P-T134	P-T134	Asphalt	80,000 bbl.	1954
P-T136	P-T136	Asphalt	80,000 bbl.	1957
P-T265	P-T265	Asphalt	5,100 bbl.	1959
P-T269	P-T269	Asphalt	5,100 bbl.	1961

EUG 3 – Cone Roof Tanks, Constructed 6/12/73 to 5/18/78 (NSPS Subpart K), Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	Capacity	Installed Date
P-T126	P-T126	FCCU charge	34,700 bbl.	10/15/74
P-T202	P-T202	FCCU charge	80,000 bbl.	6/15/74
P-T1901	P-T1901	Heavy hydrocarbons	170 bbl.	6/15/77
P-T1323	P-T1323	Asphalt	4,512 bbl.	6/15/74
P-T1324	P-T1324	Asphalt	66,590 bbl.	6/15/74

EUG 5 – Cone Roof Tanks, Constructed 5/18/78 to 7/22/84 (NSPS Subpart Ka), Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	Capacity	Installed Date
P-T264	P-T264	Gas oil	5,100 bbl.	6/15/78
P-T601	P-T601	Asphalt resin	5,000 bbl.	6/15/78
P-T1321	P-T1321	Asphalt	5,000 bbl.	2/15/79

EUG 7 – Cone Roof Tanks, Constructed after 7/23/84 (NSPS Subpart Kb), Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	Capacity	Installed Date
P-T266	P-T266	Latex	566 bbl.	6/15/89
P-T1474	P-T1474	Diesel additive	1,000 bbl.	11/1/88
P-T1475	P-T1475	High-sulfur diesel	34,700 bbl.	2/15/93
P-T200	P-T200	Diesel	80,000 bbl.	2007

Tank T-200 (previously numbered T401) and T-1475 are subject both to requirements of keeping records and monitoring vapor pressures of liquids stored.

EUG 9 – Internal Floating Roof Tanks Constructed Prior to 6/12/73, Subject to 40 CFR Part 63 Subpart CC (Group 1 Storage Vessels)

EU	Point	Normal Contents	Capacity	Installed Date
P-T146	P-T146	Premium unleaded gasoline	80,000 bbl.	1952
P-T501	P-T501	Jet fuel	25,700 bbl.	1969
P-T1471	P-T1471	Premium unleaded gasoline	34,800 bbl.	6/73
P-T257	P-T257	Unifined naphtha	10,000 bbl.	1957

Note: Tank 501 is currently in jet fuel service. Under MACT definitions, this material is considered Class 2 (low vapor pressure material with less than the 4% threshold HAP concentration). However, the vessel is constructed such that it could store a Class 1 product or intermediate, and the facility prefers to list the tank with Group 1 tanks.

EUG 10 - Internal Floating Roof Tanks, Subject to NSPS Subpart K, Subject to 40 CFR Part 63 Subpart CC

EU	Point	Normal Contents	Capacity	Installed Date
P-T1473	P-T1473	Mineral spirits/light reformate	9,600 bbl.	6/15/75
P-T67	P-T67	Crude oil	68,884 bbl.	6/1/75
P-T68	P-T68	Crude oil	68,884 bbl.	6/1/75
P-T69	P-T69	Crude oil	68,884 bbl.	6/1/75

EUG 11 – External Floating Roof Tanks, Constructed Prior to 6/12/73, Subject to 40 CFR Part 63 Subpart CC

EU	Point	Normal Contents	Capacity	Installed Date
P-T142	P-T142	Unleaded gasoline	55,000 bbl.	1954
P-T143	P-T143	Unleaded gasoline	55,000 bbl.	1957
P-T144	P-T144	Premium unleaded gasoline	55,000 bbl.	1954
P-T147	P-T147	FCCU gasoline	80,000 bbl.	1952
P-T150	P-T150	Platformate	24,800 bbl.	1952
P-T152	P-T152	Platformate	24,800 bbl.	1952
P-T154	P-T154	Heavy unicrackate	24,800 bbl.	1952
P-T164	P-T164	Light unicrackate/light reformate	10,000 bbl.	1951
P-T168	P-T168	Alkylate	35,700 bbl.	1959
P-T250	P-T250	Jet fuel	10,000 bbl.	1958
P-T251	P-T251	Mineral spirits	10,000 bbl.	1957
P-T254	P-T254	Unleaded gasoline	24,800 bbl.	1958
P-T255	P-T255	Isomerate	24,800 bbl.	1954
P-T1470	P-T1470	Unleaded gasoline	79,600 bbl.	1972

Tanks 250 and 251 currently contain hydrocarbons that are not subject to MACT controls, but the vessels are capable of compliance with 40 CFR Part 63, Subpart CC, if the liquids should be changed.

EUG 12 – External Floating Roof Tanks Constructed After 7/23/84, Subject to 40 CFR Part 63 Subpart CC

EU	Point	Normal Contents	Capacity	Installed Date
P-T155	P-T155	Naphtha	40,000-bbl.	2007
P-T70	P-T70	Crude Oil	120,000-bbl.	2007
P-T148	P-T148	Unleaded Gasoline	75,900-bbl.	1994
P-T140	P-T140	Distillates / Naphtha	80,000-bbl.	2007
P-T138	P-T138	Distillates / Naphtha	80,000-bbl.	2007
P-T203	P-T203	Gasoline / Diesel	80,000-bbl.	2009

EUG 13 – External Floating Roof Tank, Subject to NSPS Subpart Ka, Subject to 40 CFR Part 63 Subpart CC

EU	Point	Contents	Capacity	Installed Date
P-T303	P-T303	Crude oil	250,000 bbl.	5/81

EUG 14 – External Floating Roof Tank, Subject to NSPS Subpart K, Subject to 40 CFR Part 63 Subpart CC

EU	Point	Contents	Capacity	Installed Date
P-T1449	P-T1449	Crude oil	76,425 bbl.	6/74

EUG 15 – Asphalt Unit Tanks Subject 40 CFR Part 63 Subpart CC

Tank ID	Type	Material Handled	Capacity (bbls)	Height (ft)	Diameter (ft)	Constr. Date
P-T1331	Cone roof	Asphalt	5,000	40	30	2002
P-T1332	Cone roof	Asphalt	5,000	40	30	2002
P-T1333	Cone roof	Asphalt	5,000	40	30	2002
P-T1337	Cone roof	Asphalt	1,500	32	18.5	2002
P-T1338	Cone roof	Asphalt	1,500	32	18.5	2002
P-MP1330	Cone roof	Asphalt	9	8	3	2002
P-T1330	Cone roof	Asphalt	90	8	10	2002

EUG 16 – External Floating Roof Tank, Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	Capacity	Installed Date
P-T110	P-T110	Hydrocracker feed	15,000 bbl.	2013

EUG 17 – Cone Roof Tank (Sour Water With Diesel "Blanket"), Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	Capacity	Installation/ <Modification Date
P-T2051	P-T2051	Sour water / diesel	20,000-bbl.	1992

T-2051 was previously used for NaHS storage. The diesel blanket controls H_2S and ammonia emissions. The tank is used for surge control or emergency storage when the sour water stripper is down.

EUG 20 – Product Loading Facility with Vapor Controls, Subject to 40 CFR Part 63 Subpart CC and NSPS Subpart XX

EU	Point	Description	Installed Date
P-PLF1	P-PLF1	Product Loading Facility / Vapor Recovery Unit	6/86

EUG 29 - Fugitive Emissions Subject to Monitoring Requirements (40 CFR Part 63 Subpart CC and NSPS Subpart GGGa)

EU	Point	Equipment	Estimated Number of Items	Installed Date
EU-3726A	EU-3726A	GHDS Unit Fugitives	1000 gas/vapor valves	2009 - 2010
			1000 light liquid valves	
			4100 connectors	
			15 light liquid pumps	
			10 sampling connections	

EU	Point	Equipment	Estimated Number of Items	Installed Date
EU-3752A	EU-3752A	Benfree Unit Fugitives	500 gas/vapor valves 600 light liquid valves 550 flanges 10 light liquid pumps 5 relief valves	2013

EUG 30 - Fugitive Emissions Subject to Monitoring Requirements (40 CFR Part 63 Subpart CC, Consent Decree, and/or NSPS Subpart GGG)

EU	Point	Equipment	Estimated Number of Items	Installed Date
EU-3706A	EU-3706A	VOC Leakage at Bulk Gasoline Terminal	10 light liquid valves 350 heavy liquid valves 1100 flanges 25 light liquid pumps 1 compressor 15 gas relief valves	1978
EU-3722A	EU-3722A	VOC Leakage at FCCU	500 gas valves 2000 light liquid valves 4000 flanges 35 light liquid pumps	1978
EU-3725A	EU-3725A	VOC Leakage at Hydrocracker	1510 gas valves 1500 light liquid valves 100 heavy liquid valves 5600 flanges 40 light liquid pumps 5 heavy liquid pumps 20 gas relief valves 4 compressor seals	2006
EU-3732A	EU-3732A	VOC Leakage at No. 1 Crude Unit and CVU	100 gas valves 1600 light liquid valves 50 heavy liquid valves 5500 flanges 30 light liquid pumps 15 heavy liquid pumps 1 compressor seal 15 gas relief valves	1958

EU	Point	Equipment	Estimated Number of Items	Installed Date
EU-3733A	EU-3733A	VOC Leakage at No. 2 Crude Unit and No. 2 Vacuum Unit	1500 gas valves	2007
			1500 light liquid valves	
			100 heavy liquid valves	
			4000 flanges	
			25 light liquid pumps	
			20 light liquid pumps	
			20 heavy liquid pumps	
			15 gas relief valves	
			1 compressor seal	
EU-3734A	EU-3734A	VOC Leakage at CCR Platformer, No. 1 Splitter, Hysomer, Naphtha Unifiner, and Hydrogen Plant	2500 gas valves	2007
			2500 light liquid valves	
			100 heavy liquid valves	
			8750 flanges	
			60 light liquid pumps	
			10 heavy liquid pumps	
			1 compressor seal	
			15 gas relief valves	
EU-3735A	EU-3735A	VOC Leakage at Alkylation Unit, Olefin Treater, and Propylene Splitter, LPG Loading, & LPG Storage	1500 gas valves	1968
			1500 light liquid valves	
			50 heavy liquid flanges	
			4750 flanges	
			15 light liquid pumps	
			30 gas relief valves	
EU-3736A	EU-3736A	VOC Leakage at Diesel Hydrodesulfurization Unit	500 gas valves	2007
			1500 light liquid valves	
			50 heavy liquid valves	
			1,300 flanges	
			20 light liquid pumps	
			5 heavy liquid pumps	
			2 compressors	
			10 gas relief valves	
EU-3740A	EU-3740A	VOC Leakage at Steam, Utilities, and Flare System	120 gas valves	1968
			150 light liquid valves	
			20 heavy liquid valves	
			250 flanges	
			25light liquid pumps	
			5 heavy liquid pumps	
			50 gas relief valves	

EU	Point	Equipment	Estimated Number of Items	Installed Date
EU-3707	EU-3707	VOC Leakage at LPG Unit	200 gas valves	1958
			200 light liquid valves	
			5 heavy liquid valves	
			4600 flanges	
			15 light liquid pumps	
			9 gas relief valves	
EU-3727	EU-3727	VOC Leakage at RFG System	1000 gas valves	1958
			1000 light liquid valves	
			20 heavy liquid valves	
			1500 flanges	
			12 light liquid pumps	
			5 gas relief valves	
EU-3710	EU-3710	VOC Leakage at Tank Farm	1150 light liquid valves	1958
			4400 flanges	
			40 light liquid pumps	
EU-3711B	EU-3711B	VOC Leakage at Asphalt Unit	550 heavy liquid valves	1970
			2525 flanges	
EU-3732B	EU-3732B	VOC Leakage at No. 1 Crude Unit	230 light liquid valves	1958
			780 heavy liquid valves	
			1142 flanges	
			7 light liquid pumps	
			35 heavy liquid pumps	
EU-3734B	EU-3734B	VOC Leakage at CCR Platformer Area	4 heavy liquid pumps	1965
EU-3735B	EU-3735B	VOC Leakage at Aklylation Unit	40 open-ended valves	1965
			6 heavy liquid pumps	
			32 relief valves	
			1623 flanges	
EU-3711C	EU-3711C	VOC Leakage at Asphalt Unit	200 heavy liquid valves	2002
			600 flanges	
			7 heavy liquid pumps	

EUG 35 - Fugitive Emissions Subject to Monitoring Requirements (40 CFR Part 63 Subpart CC and NSPS Subpart GGG) – New Amine Treating Unit, Sour Water Stripper, Sulfur Recovery Unit, and Tail Gas Treating Unit

EU	Point	Equipment	Estimated Number of Items	Installed Date
EU-3740C	EU-3740C	VOC Leakage at New Amine Treating Unit, Sour Water Stripper, Sulfur Recovery Unit, and Tail Gas Treating Unit	156 gas valves	2006
			14 light liquid valves	
			294 heavy liquid valves	
			1,343 flanges	
			3 light liquid pumps	
			14 heavy liquid pumps	

EUG 36 - Steam Boilers Subject to NSPS Part 60 Subpart Dc and Subpart J and MACT Part 63 Subpart DDDDD

EU	Point	Equipment	MMBTUH	Installed Date
40-H1101	40-H1101	Indeck steam boiler	88.6	2009*
40-HPB1	40-HPB1	Holman package boiler	67	2012**
40-WPB1	40-WPB1	Wabash package boiler	96	2012***

* This unit was initially constructed in 2003.
**This unit was initially constructed in 1989.
***This unit was initially constructed in 2005.

EUG 37 – Fuel Gas Combustion Devices Subject to NSPS Part 60 Subpart Ja and MACT Part 63 Subpart DDDDD

EU	Point	Equipment	MMBTUH	Installed Date
P-GHH2601	GHH-2601	GHDS Splitter Reboiler	39.6	2009-10
P-GHH2602	GHH-2602	GHDS Reactor Heater	14.0	2009-10
P-GHH2603	GHH-2603	GHDS Stabilizer Reboiler	14.0	2009-10
REFORMER	REFORMER	Hydrogen Plant Reformer	126	Proposed

EUG 38 – Fuel Gas Combustion Devices Subject to NSPS Subpart J and 40 CFR 63 Subpart DDDDD

EU	Point	Equipment	MMBTUH	Installed Date
P-VH101	P-VH101	Vacuum charge heater	66	2007
P-DHH801	P-DHH801	Hydrotreater charge heater	31.1	2007
P-DHH802	P-DHH802	Fractionator charge heater	39.2	2007
P-H356	P-H356	CCR charge heater	30	2007
P-JH301	P-JH301	Fractionator charge heater	40	2007
P-CH151	P-CH151	Crude charge heater	62.4	2007 *

* modification date; heater was installed in 1972.

EUG 39 - Fuel Gas Combustion Device, Subject to 40 CFR 63 Subpart LLLLL

EU	Point	Equipment	MMBTUH	Installed Date
P-F1301	P-F1301	Asphalt oxidizer incinerator	16.8	1971

EUG 40 - Grandfathered Fuel Gas Combustion Devices, Subject to MACT Part 63 Subpart DDDDD

EU	Point	Equipment	MMBTUH	Installed Date
P-CH1	P-CH1	Crude fractionation heater	96	1953
P-CH2	P-CH2	Crude charge heater	50.4	1960
P-CH3	P-CH3	Crude preflash reboiler	35	1952
P-CH121	P-CH121	Vacuum charge heater	39.6	1959
P-JH1	P-JH1	Hydrocracker reactor heater	18.4	1965
P-JH2	P-JH2	Hydrocracker reactor heater	18.4	1965
P-JH101	P-JH101	Hydrocracker fractionator reboiler	36.8	1965
P-KH1	P-KH1	Hydrogen reforming heater	66.5	1965
P-PH3	P-PH3	Unifiner stripper reboiler	41.2	1957
P-HH1	P-HH1	Hysomer heater	15.8	1957
P-H152	P-H152	No. 2 splitter reboiler	12.5	1952
P-5H1	P-5H1	Alkylation repropanizer reboiler	84.1	1969
P-H1302	P-H1302	Tank 101 heater	10	1957
P-H1303	P-H1303	Tank 101 heater	16.8	1972
P-HT120	P-HT120	Tank 120 heater	1	1945
P-HT265	P-HT265	Tank 265 heater	1	1959
P-HT601	P-HT601	Tank 601 heater	0.7	1972
P-HT1321	P-HT1321	Tank 1321 heater	0.7	1971
P-HT1323	P-HT1323	Tank 1323 heater	0.7	1972
P-HT1324	P-HT1324	Tank 1324 heater	5	1972

A limitation on fuel sulfur has been established for P-JH101 and P-SB#5 for netting purposes. This included removing sour water stripper off-gas feed to these combustion units. Only SO_2 emissions are affected. To meet off-site SO_2 impacts limits, all grandfathered heaters and boilers are limited to 450 ppm sulfur in the fuel gas.

EUG 41 - Fuel Gas Combustion Devices Subject to Oklahoma Rules and MACT Part 63 Subpart DDDDD

EU	Point	Equipment	MMBTUH	Installed Date
P-1B8	P-1B8	Wickes steam boiler	126	1965 (modified 1978)

A limitation on fuel sulfur was established for this unit for netting purposes.

EUG 42 – Fuel Gas Combustion Devices Subject to NSPS Part 60 Subpart J and MACT Part 63 Subpart DDDDD

EU	Point	Equipment	MMBTUH	Installed Date
P-H350	P-H350	CCR charge heater	48.0	1989
P-PH5	P-PH5	Unifiner charge heater	29.0	1989
P-H601	P-H601	ROSE heater	37.4	1985
P-H960	P-H960	Glycol dryer	1.34	1982
P-H1301	P-H1301	Tank 107 heater	2.82	1989
P-1H4	P-1H4	FCCU feed preheater	108.16	1976
P-SB#4R	P-SB#4R	Nebraska Package Boiler	98.3	2007*

* This unit was initially constructed in 1984.

EUG 43 – Asphalt Unit Heater, Subject to MACT Part 63 Subpart DDDDD

EU	Point	Equipment	MMBTUH	Installed Date
P-H1331	P-H1331	Asphalt Unit hot oil heater	8.4	2002

EUG 44 – Fuel Gas Combustion Devices Subject to NSPS Part 60 Subpart J and MACT Part 63 Subpart DDDDD

EU	Point	Equipment	MMBTUH	Installed Date
P-H48001	P-H48001	SRU Hot Oil Heater	53.9	2006
P-HT134	P-HT134	Tank 134 heater	8.4	1991
P-HT136	P-HT136	Tank 136 heater	8.4	1991
P-HT264	P-HT264	Tank 264 heater	1	1996

Emissions limits for HT134, HT136, and HT264 were based on burning natural gas. WRC is authorized to use NSPS refinery fuel gas in these units.

EUG 45 – Flares, Subject to 40 CFR Part 60 Subpart Ja

EU	Point	Equipment	Installed Date
P-FS1451	P-FS1451	John Zink EEF-QS-12 smokeless flare, “South Flare”	1957
P-FS1503	P-FS1503	0.2 MMBTUH Hydrocracker Flare	2006
P-FS1403	P-FS1403	West Flare	2013

WRC's prior Title V permit and subsequent modifications identified the South Flare as a grandfathered source (not subject to NSPS Subpart J). On October 6, 2009, AQD issued Permit No. 98-117-TV (M-10) for operation of the Gasoline Hydrodesulfurization Unit (GHDS). The permit application included a change adding an emergency depressurization valve that would relieve to the new North Flare ("Peabody Flare"). So the South Flare change in applicability to NSPS Subpart J was incorrect. The South Flare became subject to NSPS Subpart Ja in a construction project that was permitted in M-11 and occurred in 2009. Based on the modification date, the South Flare became subject to NSPS Subpart Ja in 2009 and was never subject to Subpart J.

EUG 46 – Fuel Gas Combustion Devices Subject to NSPS Part 60 Subpart Ja and MACT Part 63 Subpart DDDDD

EU	Point	Equipment	MMBTUH	Installed Date
52-H01	52-H01	Benfree Reboiler	65	2013

EUG 51 – Miscellaneous Process Vents

EU	Point	Equipment	Installed Date
P-VENT7	P-VENT7	Asphalt light ends recovery sump	1970

EUG 53 – Process Vents Subject to Permit Limitations and 40 CFR Part 63 Subpart UUU

EU	Point	Equipment	Installed Date
P-VENT6	P-VENT6	CCR Regenerator vent	1989

EUG 54 – Molten Sulfur Pit

EU	Point	Normal Contents	Capacity	Installed Date
P-SP301	P-SP301	Sulfur	348.7 LT	2006

EUG 56 – Wastewater System Subject to 40 CFR Part 63 Subpart CC

EU	Point	Equipment	Installed Date
P-WW1	P-WW1	Process wastewater systems and open sewers	various

EUG 57 – Wastewater Systems Subject to NSPS Subpart QQQ and 40 CFR Part 63 Subpart CC

EU	Point	Equipment	Installed Date
EU-WW2	EU-WW2	CCR drain	1989
		D-208 drain	1993
		S-1450 drain	1993
		S-1451 drain	1991

EUG 58 – Open API Separator

EU	Point	Equipment	Installed Date
P-API1	P-API1	Open API separator	1968

EUG 59 – Covered API Separator Subject to NSPS Part 60 Subpart QQQ

EU	Point	Equipment	Installed Date
P-API2	P-API2	Covered API separator	1978

EUG 60 – Wastewater Systems Subject to NSPS Subpart QQQ and 40 CFR Part 63 Subpart CC in SRU, Diesel Hydrodesulfurization Area, Vacuum Unit 2 Area, GHDS Unit, Benfree Unit, and Hydrogen Plant Reformer

EU	Point	Equipment	Installed Date
EU-WW3	EU-WW3	Closed Process drains (SRU)	2006
		Closed Process Junction boxes (SRU)	2006
EU-WW4	EU-WW4	25 P-trap drains (DHDU)	2007
		2 Junction boxes (DHDU)	2007
EU-WW5	EU-WW5	25 P-trap drains (No. 2 Crude Unit Vacuum Unit)	2007
		2 Junction boxes (No. 2 Crude Unit Vacuum Unit)	2007
EU-WW6	EU-WW6	10 P-trap drains (GHDS)	2009-10
		2 Junction boxes (GHDS)	2009-10
EU-52WW	EU-52WW	Benfree Unit Drains	2013
EU-53WW	EU-53WW	5 SMR Drains	Proposed

EUG 61 – Benfree Unit Oil-Water Separator Subject to 40 CFR 60 Subpart QQQ and 40 CFR 63 Subpart CC

EU	Point	Equipment	Installed Date
52-T01	52-T01	Benfree Unit Separator	2013

EUG 64 – GHDS Oil-Water Separator subject to NSPS QQQ and 40 CFR 63, Subpart CC

EU	Point	Equipment	Installed Date
P-API3	P-API3	GHDS Unit oil-water separator	2009-10

EUG 66 – Cooling Towers

EU	Point	Equipment	Installed Date
P-CWT1	P-CWT1	Crude Unit cooling tower	1958
P-CWT3	P-CWT3	FCCU cooling tower	1958
P-CWT5	P-CWT5	Alky Unit cooling tower	1968

* P-CWT2, Vacuum unit cooling tower, was demolished.

EUG 67 – Hydrocracker Cooling Tower

EU	Point	Equipment	Modified Date
P-CWT4	P-CWT4	Hydrocracker cooling tower	2006

The circulation rate for this cooling tower is expected to remain constant, therefore, emissions will not change.

EUG 68 – GHDS Unit and Benfree Unit Cooling Towers Subject to 40 CFR 63 Subpart CC

EU	Point	Equipment	Installed Date
P-CWT6	P-CWT6	GHDS Unit cooling tower	2009-10
52-CT	52-CT	Benfree Unit cooling tower	2013

EUG 80 – Non-gasoline Loading Racks

EU	Point	Equipment	Installed Date
P-LR2T	P-LR2T	Gas oil truck unloading rack	1958
P-LT2R	P-LT2R	Gas oil rail unloading rack	1958
P-LR3T	P-LR3T	Solvent truck loading rack	1958
P-LT3R	P-LT3R	Solvent rail loading rack	1958
P-LR5T	P-LR5T	Asphalt truck loading rack	1960
P-LR5R	P-LR5R	Asphalt/slurry truck loading rack	1960
P-LR6T	P-LR6T	Slurry truck loading rack	1960

EUG 81 – New Non-gasoline Loading Rack

EU	Point	Equipment	Installed Date
P-LR4T	P-LR4T	JP-8 truck loading rack	1996

EUG 82 – Molten Sulfur Loading Racks

EU	Point	Equipment	Installed Date
P-SLRR	P-SLRR	Sulfur railcar loading rack	2006
P-SLRT	P-SLRT	Sulfur truck loading rack	2006

EUG 85 – FCCU Regenerator Subject to NSPS Subpart J and 40 CFR Part 63 Subpart UUU

EU	Point	Equipment	Installed Date
P-1ME258	P-1ME258	FCCU catalyst regenerator	1978

EUG 87 – SRU Tail Gas Incinerator Subject to NSPS Subpart J and 40 CFR Part 63 Subpart UUU

EU	Point	Equipment	MMBTUH	Installed Date
P-TGIS1	P-TGIS1	SRU Tail Gas Incinerator	7.55	2006

EUG 90 – Miscellaneous Insignificant Heaters

Heater Designation	Location	MMBTUH
IH-1	Kyle house	0.10
IH-2	Main office	0.375
IH-3	Webb house	0.10
IH-4	Laboratory	0.191
IH-5	Laboratory	0.15
IH-6	Laboratory	0.15
IH-7	Laboratory	0.15
IH-8	Laboratory	0.15
IH-9	Laboratory	0.191
IH-10	Electrical shop	0.14
IH-11	Maintenance office	0.15
IH-12	Maintenance office	0.14
IH-13	East shop	2.25
IH-14	West shop	2.25

EUG 91 – Miscellaneous Reciprocating Engines

Unit ID	Location	Unit Description	Unit Capacity
IE-1	Wastewater Plant	Caterpillar 3406B stormwater pump	300 HP
IE-2	Portable	Briggs/Stratton 195432 emergency generator	8 HP
IE-3	Portable	Generac 09441-2 emergency generator	5 HP
P-1183	Firewater Pump House	Cummins NT 855-F4 fire water pump	340 HP
P-1184	Firewater Pump House	Caterpillar 3406B fire water pump	375 HP
P-1185	Firewater Pump House	Cummins QSM11 fire water pump	400 HP

EUG 92 – Miscellaneous Insignificant Storage Tanks

Unit ID	Location	Capacity, Gallons	Normal Contents
IT-1	Shop	2,000	Gasoline
IT-2	Shop	1,000	Diesel
IT-3	FCCU	1,975	Lube oil
IT-4	Platformer	1,321	Lube oil
IT-5	FCCU	1,000	Lube oil
T-1417	Truck rack	2,000	Fuel additive
IT-7	#2 Crude Unit	1,000	Corrosion inhibitor
IT-8	#2 Crude Unit	750	Corrosion inhibitor
IT-9	FCCU	1,000	Corrosion inhibitor
IT-10	FCCU	1,000	Corrosion inhibitor
IT-11	#1 Crude Unit	2,000	Embreak 2W157
IT-13	72 Manifold	250	Hi-Tec 4551
T-1414	Truck rack	6,000	Fuel additive
T-1416	Truck rack	6,000	Fuel additive
IT-17	Crude Vacuum Unit	550	Non-hydrocarbon
IT-18	Hydrocracker	3,171	Mystik Synguard
IT-19	ROSE Unit	2,325	Solvent cleaner
IT-20	Boilerhouse	400	Non-hydrocarbon
IT-21	FCCU	1,600	Corrosion inhibitor
IT-22	Lt. Oils Blender	765	Corrosion inhibitor
IT-23	FCCU	750	Corrosion inhibitor
IT-24	#1 Crude Unit	1,000	Corrosion inhibitor
IT-25	#1 Crude Unit	750	Corrosion inhibitor
IT-26	#2 Crude Unit	750	Corrosion inhibitor
IT-27	#2 Crude Unit	1,000	Corrosion inhibitor
IT-28	72 Manifold	250	Fuel additive
IT-29	#1 Crude Unit	750	Corrosion inhibitor
IT-30	#2 Crude Unit	1,000	Corrosion inhibitor
IT-31	#2 Crude Unit	200	Corrosion inhibitor
IT-32	Platformer	560	Corrosion inhibitor
IT-33	Alky Unit	564	Corrosion inhibitor
IT-34	FCCU	560	Corrosion inhibitor
IT-35	72 Manifold	673	Corrosion inhibitor
IT-36	FCCU	1,000	Corrosion inhibitor
IT-37	Products Handling	560	Corrosion inhibitor
T-1424	JP-8 Rack	2,000	Fuel additive
T-1413	Truck rack	8,000	TFA-4906
IT-40	FCCU	6,428	TFA-4906
IT-41	#1 Crude Unit	2,000	Anti-foulant
IT-42	#2 Crude Unit	1,000	Anti-foulant

EUG 92 – Miscellaneous Insignificant Storage Tanks - Continued

Unit ID	Location	Capacity, Gallons	Normal Contents
IT-43	FCCU	300	Non-hydrocarbon
IT-44	Alky Unit	200	Non-hydrocarbon
IT-45	#1 Crude Unit	1,000	Non-hydrocarbon
T-1418	Truck rack	1,000	Fuel additive
T-6092	72 Manifold	5,600	Fuel additive
T-1426	Truck rack	1,000	Fuel additive
T-1425	Near T-1475	1,000	Fuel additive
T-1486	Near T-201	1,000	Fuel additive
T-1476	Truck rack	7,140	Diesel additive
P-T141	Diesel blending	8,000	Cetane
P-T1424	Diesel blending	2,000	Diesel additive
P-T1425	Diesel blending	1,000	Blue diesel dye
P-T1486	Diesel blending	1,000	Blue diesel dye
P-T2001	Asphalt blending	21,000	Oily wastewater
P-t2002	Asphalt blending	4,200	Oily wastewater

EUG 93 – Miscellaneous Insignificant Process Vents

Unit ID	Description
DAVENT-1	Reformer Deaerator Vent
BDVENT-1	Reformer Blowdown Vent
PSA Hydrogen	Reformer PSA Hydrogen Vent

SECTION IV. EMISSIONS

The facility operates up to 8,760 hours per year. Emissions were estimated using the following methods and references:

New Units

- Emissions from the new 126 MMBTUH heater and reformer were calculated using manufacturer emissions factors for CO, VOC, and PM; NSPS Subpart Ja limits for NO_X (60 ppmv stack concentration); AP-42 Chapter 1.4 emission factors for SO_2, and 40 CFR 98 factors for greenhouse gases. Annual emissions were based on 1,752 MMSCFY fuel gas usage which is divided between fuel combusted for heat and methane used as a raw material in hydrogen production.

Heat Input, MMBTUH	Pollutant	Emission Factor	Emissions	
			lb/hr	TPY
126	NOx	0.0625 lb/MMBTU	7.44	29.63
	CO	0.0317 lb/MMBTU	3.78	15.03
	VOC	0.003 lb/MMBTU	0.32	1.26
	PM_{10} $PM_{2.5}$	0.0038 lb/MMBTU	0.76	3.01
	SO_2	162 ppm / 60 ppm	0.13	0.53
	GHG	126.5 lb/MMBTU plus CO_2e as reformer reaction product	26,462	105,365

- Process drain VOC emissions were based on an estimated 5 new drains, and an emission factor and control efficiency from EPA's "VOC Emissions from Petroleum Refinery Wastewater Systems – Background Information for Proposed Standards" (EPA-450/3-85-001a).

Number of Drains	Pollutant	Emission Factor, lb/hr/unit	Control Efficiency	VOC Emissions	
				lb/hr	TPY
5	VOC	0.07	40%	0.21	0.92

- Process fugitive emissions will be CO from new equipment in the reformer. Fugitive leakage calculations used estimated numbers of new components and emissions factors from EPA's "1995 Protocol for Equipment Leak Emission Estimates," Table 2-4. Maximum anticipated CO concentrations (ranging from 0.04% to 23.14%) were used for each section of the reformer. Fugitive CO emissions were stated at 2.03 lb/hr and 8.88 TPY.

- The project is expected to add 10 gas/vapor valves and 100 gas/vapor flanges to EU-3725A. Using factors from EPA's "1995 Protocol for Equipment Leak Estimates," Table 2-2, added VOC emissions from the added components are less than 0.01 TPY.

- Process vent emissions were based on engineering estimates of maximum and normal discharge rates. There are negligible emissions of regulated pollutants expected from the PSA Hydrogen vent.

VENT ID	Max Flow lb-mole/hr	Average Flow, lb-mole/hr	Pollutant	Concentration	Molecular Weight	VOC	
						lb/hr	TPY
DAVENT	68	68	VOC	200	58.4	0.80	3.49
			MeOH	120	32	0.26	1.15
			TOTALS			**1.06**	**4.64**
BDVENT	89	27	VOC	200	58.4	1.04	1.37
			MeOH	120	32	0.34	0.45
			TOTALS			**1.38**	**1.82**

<u>Increased Utilization of Existing Units</u>

- Potential VOC emissions from diesel tank T-200 were calculated assuming increased annual throughput of 3,000 BPD (1,095,000 BPY). Tanks T-203 and T-253 will be used to store the additional diesel production from the project; however, total permitted throughputs for these tanks will not increase. Worst-case VOC emissions increases from storage of an additional 3,000 BPD (1,095,000 BPY) of diesel in a combination of tanks T-200, T-203, and T-253 were also calculated for PSD Analysis purposes. Baseline Actual Emissions were determined for the years 2011- 2012 at 1.17 TPY; Projected Actual Emissions were calculated with the added 3,000 BPD diesel, assumed all through T-200 (worst-case scenario; the other tanks have floating roofs) at 1.90 TPY for a net change of 0.73 TPY VOC.

- Increased utilization of Flare FS1403 (EUG 45) used factors from AP-42 (1/95), Section 13.5 of 0.068 lb/MMBTU NOx and 0.37 lb/MMBTU CO. GHG (CO_2e) emissions were calculated using the methods in 40 CFR Part 98, based on heat and carbon content of the streams. The following events, flows, and heating values were used to calculate maximum added heat release from that flare:

Event	Hours Per Year [1]		Max Flow Per Hour [1] MSCFH	Heating Value [1] BTU/SCF	MMBTU per Year [1]
Natural Gas Fuel	72		193.44	1,017.38	14,170.32
PSA Feed	432		739.59	321.6	102,755.5
PSA Hydrogen	72		458.33	323.49	10,675.44
PSA Tail Gas	432		277.37	317.93	38,098.08
Nitrogen Purge	168		140.43	300.09	7,079.52
Offspec Flaring	72		458.33	323.49	10,675.44
TOTALS					**183,454.32**

[1] All durations, flow rates, and heating values represented in this table are estimates only and do not represent permit limitations.

Post-project emissions from the hydrocracker cooling tower were based on a unit capacity of circulating 8,000 GPM cooling water and factors in AP-42 (1/95), Table 5-1, while BAE were taken from recent emissions inventories. PAE was calculated at 1.47 TPY VOC and 0.48 TPY PM_{10} / $PM_{2.5}$. BAE were calculated at 1.04 TPY VOC and 0.35 TPY PM_{10}, for net changes of 0.43 TPY VOC and 0.13 TPY PM_{10} / $PM_{2.5}$.

A project is a major modification if it causes a significant emissions increase or a significant net emission increase. A significant emissions increase of a regulated NSR pollutant will occur if the sum of emissions increases for each EU equals or exceeds the amount that is significant for that pollutant. For each EU, the emission increases are based on the difference between the "potential emissions" (PTE) and the "baseline actual emissions" (BAE). Facilities that use the PTE for existing units are not subject to the recordkeeping requirements in OAC 252:100-8-36.2(c). New emissions units must use their PTE and BAE are equal to zero.

Baseline Actual Emissions (BAE) are equal to zero for the proposed reformer. Project emission increases include emissions from newly constructed emission units, existing emission units proposed for modification, existing emission units that are debottlenecked, and other associated emission increases. No existing emission units are proposed for modification or are debottlenecked and there are no other associated emission increases other than increased utilization.

Project Emissions Increases (TPY)

Unit	NOx	CO	VOC	PM_{10} $PM_{2.5}$	SO_2	GHG
Hydrogen Plant Reformer	29.63	15.03	1.26	3.01	0.53	105,365
Fugitive CO Leakage	--	8.88	---	--	--	--
Deaerator Vent	--	--	4.64	--	--	--
Blowdown Vent	--	--	1.81	--	--	--
Flare FS1403	6.24	14.13	0.06	--	--	11,539
Process Drains	--	--	0.92	--	--	--
Diesel Tanks	--	--	0.73	--	--	--
VOC Leakage at Hydrocracker	--	--	0.01	--	--	--
Cooling Tower	--	--	1.04	0.13	--	--
TOTALS	**35.87**	**38.04**	**10.47**	**3.14**	**0.53**	**116,905**
PSD Levels of Significance	**40**	**100**	**40**	**15 / 10**	**40**	**75,000**

GHG emissions exceed PSD levels of significance. All other emission increases are below PSD levels of significance.

If the project results in a significant emission increase, the project has to be reviewed for a significant net emission increase. Net emissions increases include the increase in emissions from a particular change and any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable. An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs within 3 years prior to the date that the increase from a particular change occurs. An increase or decrease in actual emissions is creditable only if the AQD has not relied on it in issuing a PSD permit for the source which is in effect when the increase in actual emissions from the particular change occurs.

<u>Other Existing Units</u>

- Holman and Wabash package boiler emissions are based on factors in AP-42 (7/98), Section 1.4, with a 15% safety factor added to factors for NOx, CO, VOC, and PM_{10}. SO_2 emissions are based on the NSPS Subpart J limit of 159 ppm sulfur in fuel.

- Tank emissions were calculated using the EPA program, TANKS4.09.

- Emissions from P-CH151 were based on manufacturer guarantees for NOx (0.06 lb/MMBTU); AP-42 (7/98) Section 1.4 for CO, VOC, and PM; and 159 ppm sulfur in fuel for SO_2.

- Emissions from the Boiler #4 ("Nebraska Boiler," P-SB#4R) were based on factors in AP-42 (7/00), Section 1.4, with a 10% safety factor for all emissions except SO_2; SO_2 emissions were based on 159 ppm sulfur in fuel, 1,020 BTU/SCF fuel gas heating value (note: this heating value is higher than the more conservative 800 BTU/SCF used for all other fuel-burning equipment).

- Except for the FCCU, SRU, flares, and stationary engines, all other combustion emissions were based on AP-42 (7/98), Table 1.4-1. SO_2 emissions from NSPS-applicable combustion units assumed 159 ppm sulfur in fuel and 800 BTU/SCF heating value, while SO_2 emissions for non-NSPS units were based on 450 ppm sulfur.

- FCCU emissions were taken from Permit No. 1998-117-C (PSD), except for CO and VOC emissions. VOC emissions were based on AP-42 (1/95), Section 5.1, assuming 98% control of VOC for the regenerator. CO was based on a maximum of 50 ppm in the flue gas and demonstrated by stack testing.

- Fugitive VOC leakages from valves, etc., were estimated using factors in the EPA publication, "Protocol for Equipment Leak Emission Estimates" (EPA-453/R-95-017), Table 2-2.

- Wastewater system emissions were estimated using factors from AP-42 (1/95), Table 9.1-2 and the Background Information Document (BID) for NSPS Subpart QQQ.

- Gasoline loading emissions were based on the MACT limitation.

- Vent emissions were based on stack testing.

- Gas-fired engine emissions were based on AP-42 (7/00), Section 3.2, while stationary diesel engine emissions were based on AP-42 (10/96), Section 3.3.

- Non-gasoline loading rack emissions were estimated using the techniques of “Gasoline Distribution Industry (Stage I) – Background Information for Promulgated Standards” (EPA-453/R-94-002b).

- Asphalt blowstill emissions were calculated based on AP-42 (1/95), Section 5.1.2.7.

- Flare SO_2 emissions were based on the NSPS Subpart J limit of 159 ppm sulfur, while all other emissions were based on AP-42 (1/95) Section 13.5 factors.

- SRU SO_2 emissions were based on the NSPS Subpart J limit of 250 ppm SO_2, while CO emissions were based on manufacturer guarantees of 300 ppm, and NOx, VOC, and PM emissions were based on AP-42 (7/00) with a 50% safety factor added.

- “Benfree Unit” Emissions:

    - Emissions from the new 65 MMBTUH reboiler were calculated using manufacturer emissions factors for NOx and CO; AP-42 (7/98) Section 1.4 for VOC, adjusted for normal refinery fuel gas VOC content (approximately 50%); AP-42 (7/98) Section 1.4 for PM (all PM is assumed to be $PM_{2.5}$, but since RFG is normally 50% hydrogen, 50% of the PM factor was used); NSPS Subpart Ja limits for SO_2 (162 ppm short-term and 60 ppm annual); and 40 CFR 98 factors for greenhouse gases. An average heating value of 800 BTU/SCF was assumed for SO_2 calculations. Since RFG is normally approximately 50% hydrogen, which burns without creating PM, VOC, CO, or CO_2, emissions calculations are conservative.

    - Cooling tower emissions were based on a circulation rate of 1,200 GPM, with VOC emissions factors from AP-42 (1/95) Section 5.1 and PM emission factors from AP-42 (1/95) Section 13.4.

    - Oil-water separator emissions were based on a circulation rate of 71 GPM, with VOC emissions factors from AP-42 (1/95) Section 5.1.

EUG 1 – Cone Roof Tanks, Subject to 40 CFR Part 63 Subpart CC (Group 2 Vessels)

EU	Point	Normal Contents	VOC	
			lb/hr	TPY
P-T108	P-T108	Jet kerosene	0.07	0.17
P-T111	P-T111	Jet kerosene	0.03	0.05
P-T162	P-T162	JP-8 additive	0.01	0.01
P-T252	P-T252	Slurry oil	0.01	0.01
P-T253	P-T253	High-sulfur diesel	0.10	0.24
P-T256	P-T256	Jet kerosene	0.02	0.05
P-T260	P-T260	Slurry oil	0.03	0.11
P-T262	P-T262	Gas oil	0.11	0.14
P-T263	P-T263	Slop oil	0.01	0.05
P-T1441	P-T1441	Jet kerosene	0.43	0.43
P-T1472	P-T1472	Low-sulfur diesel	0.44	0.74
P-T2052	P-T2052	Slop oil	0.01	0.01
P-T101	P-T101	Asphalt	0.25	1.11
P-T107	P-T107	Asphalt	0.16	0.69
P-T120	P-T120	Asphalt	0.01	0.04
P-T134	P-T134	Asphalt	0.06	0.24
P-T136	P-T136	Asphalt	0.04	0.19
P-T265	P-T265	Asphalt	0.32	1.39
P-T269	P-T269	Asphalt	0.01	0.04
TOTALS			**2.12**	**5.71**

EUG 3 – Cone Roof Tanks, Constructed 6/12/73 to 5/18/78 (NSPS Subpart K), Not Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	VOC	
			lb/hr	TPY
P-T126	P-T126	FCCU charge	0.01	0.01
P-T202	P-T202	FCCU charge	0.01	0.01
P-T1901	P-T1901	Heavy hydrocarbons	0.01	0.01
P-T1323	P-T1323	Asphalt	11.26	24.66
P-T1324	P-T1324	Asphalt	0.20	0.87
TOTALS			**11.49**	**25.56**

EUG 5 – Cone Roof Tanks, Constructed 5/18/78 to 7/22/84 (NSPS Subpart Ka), Not Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	VOC	
			lb/hr	TPY
P-T264	P-T264	Gas oil	8.34	18.28
P-T601	P-T601	Asphalt resin	8.07	17.68
P-T1321	P-T1321	Asphalt	11.02	24.14
TOTALS			**27.43**	**60.10**

EUG 7 – Cone Roof Tanks, Constructed after 7/23/84 (NSPS Subpart Kb), Not Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	VOC	
			lb/hr	TPY
P-T266	P-T266	Latex	0.71	1.55
P-T1474	P-T1474	Diesel additive	0.73	1.61
P-T1475	P-T1475	High-sulfur diesel	0.17	0.74
P-T200	P-T200	Diesel	0.43	1.90
TOTALS			**2.04**	**5.80**

EUG 9 – Internal Floating Roof Tanks Constructed Prior to 6/12/73, Subject to 40 CFR Part 63 Subpart CC (Group 1 Storage Vessels)

EU	Point	Normal Contents	VOC	
			lb/hr	TPY
P-T146	P-T146	Premium unleaded gasoline	2.38	8.94
P-T501	P-T501	Jet fuel	0.01	0.04
P-T1471	P-T1471	Premium unleaded gasoline	1.17	3.21
P-T257	P-T257	Unifined naphtha	0.04	0.17
TOTALS			**3.60**	**12.36**

EUG 10 - Internal Floating Roof Tanks, NSPS Subpart K, Subject to 40 CFR Part 63 Subpart CC

EU	Point	Normal Contents	VOC	
			lb/hr	TPY
P-T1473	P-T1473	Mineral spirits/light reformate	3.44	7.54
P-T67	P-T67	Crude oil	3.83	8.38
P-T68	P-T68	Crude oil	3.83	8.38
P-T69	P-T69	Crude oil	3.83	8.38
TOTALS			**14.93**	**32.68**

EUG 11 – External Floating Roof Tanks, Constructed Prior to 6/12/73, Subject to 40 CFR Part 63 Subpart CC

EU	Point	Normal Contents	VOC	
			lb/hr	TPY
P-T142	P-T142	Unleaded gasoline	6.58	28.80
P-T143	P-T143	Unleaded gasoline	6.60	28.92
P-T144	P-T144	Premium unleaded gasoline	6.60	28.91
P-T147	P-T147	FCCU gasoline	1.68	7.34
P-T150	P-T150	Platformate	2.40	10.53
P-T152	P-T152	Platformate	2.30	10.09
P-T154	P-T154	Heavy unicrackate	1.97	8.61
P-T164	P-T164	Light unicrackate/light reformate	2.84	12.43
P-T168	P-T168	Alkylate	2.00	8.76
P-T250	P-T250	Jet fuel	0.03	0.11
P-T251	P-T251	Mineral spirits	0.43	1.88
P-T254	P-T254	Unleaded gasoline	1.14	5.00
P-T255	P-T255	Isomerate	1.88	8.24
P-T1470	P-T1470	Unleaded gasoline	6.53	28.60
TOTALS			**42.97**	**188.22**

EUG 12 – External Floating Roof Tanks Constructed After 7/23/84, Subject to 40 CFR Part 63 Subpart CC

EU	Point	Normal Contents	VOC	
			lb/hr	TPY
T-155	PT-155	Naphtha	0.38	1.66
T-70	PT-70	Crude Oil	1.22	5.31
T-148	PT-148	Gasoline	3.73	16.33
T-140	PT-140	Distillates / Naphtha	2.41	10.54
T-138	PT-138	Distillates / Naphtha	2.38	10.42
T-203	PT-203	Gasoline / Diesel	0.87	3.82
TOTALS			**10.97**	**48.08**

EUG 13 – External Floating Roof Tank, Subject to NSPS Subpart Ka, Subject to 40 CFR Part 63 Subpart CC

EU	Point	Normal Contents	VOC	
			lb/hr	TPY
P-T303	P-T303	Crude oil	14.41	31.55

EUG 14 – External Floating Roof Tank, Subject to NSPS Subpart K, Subject to 40 CFR Part 63 Subpart CC

EU	Point	Normal Contents	VOC	
			lb/hr	TPY
P-T1449	P-T1449	Crude oil	13.75	30.11

EUG 15 - Tanks Subject 40 CFR Part 63 Subpart CC

EU	Point	Normal Contents	VOC	
			lb/hr	TPY
P-T1331	P-T1331	Polymer Modified Asphalt	0.30	0.44
P-T1332	P-T1332	Polymer Modified Asphalt	0.30	0.44
P-T1333	P-T1333	Polymer Modified Asphalt	0.30	0.44
P-T1337	P-T1337	Blending Tank	0.2	0.30
P-T1338	P-T1338	Blending Tank	0.2	0.30
P-MP1003	P-MP1003	Mill Skid Tank	0.2	0.35
P-T1330	P-T1330	Wetting Tank	0.1	0.08
TOTALS			**1.90**	**2.36**

EUG 16 – External Floating Roof Tank, Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	VOC	
			lb/hr	TPY
P-T110	P-T110	Hydrocracker feed	0.29	0.54

EUG 17 – Cone Roof Tank (Sour Water With Diesel Blanket), Not Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	VOC	
			lb/hr	TPY
P-T2051	P-T2051	Diesel / Sour Water	0.11	0.46

EUG 20 – Product Loading Facility with Vapor Controls, Subject to 40 CFR Part 63 Subpart CC and NSPS Subpart XX

EU	Point	Process	VOC	
			lb/hr	TPY
P-PLF1	P-PLF1	Product Loading Facility / Vapor Recovery Unit	3.08	12.67

EUG 29 - Fugitive Emissions Subject to Monitoring Requirements (40 CFR Part 63 Subpart CC and/or NSPS Subpart GGGa)

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff. *	lb/hr	TPY
EU-3726A	VOC Leakage at GHDS Unit	Gas/vapor valves	1000	0.059	97%	1.770	7.553
		lt liq valves	1000	0.024	97%	0.720	3.154
		flanges	4100	0.00055	30%	1.578	6.914
		lt liq pumps	15	0.251	85%	0.565	2.474
		sampling	10	0.033	97%	0.001	0.001
TOTALS						**4.634**	**20.295**

*Based on TCEQ guidance.

EUG 30 - Fugitive Emissions Subject to Monitoring Requirements (40 CFR Part 63 Subpart CC, Consent Decree and/or NSPS Subpart GGG)

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
EU-3706A	VOC Leakage at Bulk Gasoline Terminal	lt liquid valves	10	0.024	84.3%	0.038	0.165
		hvy liq valves	350	0.0005	0%	0.175	0.767
		flanges	1100	0.00056	76.4%	0.145	0.637
		lt liq pumps	25	0.25	89.4%	0.662	2.902
		gas relief valves	15	0.36	72.6%	1.480	6.481
TOTALS						**2.500**	**10.951**

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
EU-3722A	VOC Leakage at FCCU	gas valves	500	0.0591	98.2%	0.532	2.330
		lt liq valves	2000	0.024	84.3%	7.536	33.008
		flanges	4000	0.00055	76.4%	0.519	2.274
		lt liq pumps	35	0.251	89.4%	0.931	4.079
TOTALS						**9.518**	**41.690**

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	VOC	
						lb/hr	TPY
EU-3725A	VOC Leakage at Hydrocracker	gas valves	1510	0.0177	98.2%	0.479	2.096
		lt liquid valves	1500	0.024	84.3%	05.652	24.756
		hvy liq valves	100	0.0005	0%	0.050	0.219
		flanges	5600	0.00055	76.4%	0.717	3.139
		lt liq pumps	40	0.25	89.4%	1.060	4.643
		hvy liq pumps	5	0.046	35.3%	0.149	0.652
		gas relief valves	20	0.0177	98.2%	0.006	0.028
		compr. seals	4	1.400 *	85.8%	0.398	1.741
TOTALS						**8.511**	**37.274**

* since the stream is expected to be at least 50% hydrogen, emissions have been reduced by 50%.

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
EU-3732A	VOC Leakage at No. 1 Crude Unit	gas valves	100	0.0177	98.2%	0.032	0.140
		lt liq valves	1600	0.024	84.3%	6.029	26.406
		hvy liq valves	50	0.0005	0%	0.025	0.110
		flanges	5500	0.00056	76.4%	0.727	3.184
		lt liq pumps	30	0.25	89.4%	0.795	3.482
		hvy liq pumps	15	0.046	35.3%	0.446	1.955
		gas relief valves	15	0.36	100%	0.001	0.001
		compressor	1	1.4	85.9%	0.197	0.865
TOTALS						**8.251**	**36.141**

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
EU-3733A	VOC Leakage at No. 2 Crude Unit and No. 2 Vacuum Unit	gas valves	1500	0.0177	98.2%	0.478	2.093
		lt liquid valves	1500	0.024	84.3%	5.652	24.756
		hvy liq valves	100	0.0005	0%	0.050	0.219
		Flanges	4000	0.00056	76.4%	0.529	2.315
		lt liq pumps	25	0.25	89.4%	0.663	2.902
		hvy liq pumps	20	0.046	35.3%	0.595	2.607
		gas relief valves	15	0.36	72.6%	1.480	6.481
		compr. seal	1	1.400	85.8%	0.199	0.871
TOTALS						**9.645**	**42.244**

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
EU-3734A	VOC Leakage at CCR Platformer, No. 1 Splitter, Hysomer, Naphtha Unifiner, and Hydrogen Plant	gas valves	2500	0.0177	98.2%	0.797	3.489
		lt liquid valves	2500	0.024	84.3%	9.420	41.260
		hvy liq valves	100	0.0005	0%	0.050	0.219
		flanges	8750	0.00056	76.4%	1.156	5.065
		lt liq pumps	60	0.25	89.4%	1.590	6.964
		hvy liq pumps	10	0.046	35.3%	0.298	1.304
		gas relief valves	15	0.36	72.6%	1.480	6.481
		compr. seal	1	1.400	85.8%	0.199	0.871
TOTALS						**14.989**	**65.651**

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
EU-3735A	VOC Leakage at Alkylation Unit, Propylene Splitter, Butane Defluorinator, LPG Loading and LPG Storage	gas valves	1500	0.0177	98.2%	0.478	2.093
		lt liq valves	1500	0.024	84.3%	5.652	24.756
		hvy liq valves	50	0.0005	0%	0.025	0.110
		flanges	4750	0.00056	76.4%	0.628	2.750
		lt liq pumps	15	0.25	89.4%	0.398	1.741
		gas relief valves	30	0.36	72.6%	2.959	12.961
TOTALS						**10.139**	**44.410**

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
EU-3736A	VOC Leakage at Diesel HDS Unit	gas valves	500	0.0177	98.2%	0.159	0.698
		lt liquid valves	1500	0.024	84.3%	5.652	24.756
		hvy liq valves	50	0.0005	0%	0.025	0.110
		flanges	1300	0.00056	76.4%	0.172	0.753
		lt liq pumps	20	0.25	89.4%	0.530	2.321
		hvy liq pumps	5	0.046	35.3%	0.149	0.652
		compr. seal	1	1.400	85.8%	0.199	0.871
		gas relief valves	10	0.36	72.6%	0.986	4.320
TOTALS						**7.872**	**34.480**

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
EU-3740A	VOC Leakage at Steam, Utilities, and Flare System	gas valves	120	0.059	98.2%	0.127	0.558
		lt liq valves	150	0.024	84.3%	0.565	2.476
		hvy liq valves	20	0.0005	0%	0.010	0.044
		flanges	250	0.00056	76.4%	0.033	0.145
		lt liq pumps	25	0.25	89.4%	0.663	2.902
		hvy liq pumps	6	0.046	0%	0.276	1.209
		gas relief valves	50	0.36	72.6%	4.932	21.602
TOTALS						**6.606**	**28.935**

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
EU-3707	VOC Leakage at LPG Unit	gas valves	200	0.0177	98.2%	0.064	0.279
		lt liq valves	200	0.024	84.3%	0.754	3.301
		hvy liq valves	5	0.0005	0%	0.003	0.011
		flanges	4600	0.00056	76.4%	0.608	2.663
		lt liq pumps	15	0.25	89.4%	0.398	1.741
		gas relief valves	15	0.36	100%	0.001	0.001
TOTALS						**1.825**	**7.995**

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
EU-3727	VOC Leakage at RFG System	gas valves	1000	0.0177	98.2%	0.319	1.395
		lt liq valves	1000	0.024	84.3%	3.768	16.504
		hvy liq valves	20	0.0005	0%	0.010	0.044
		flanges	1500	0.00056	76.4%	0.198	0.868
		lt liq pumps	12	0.25	89.4%	0.318	1.393
		gas relief valves	5	0.36	100%	0.001	0.001
TOTALS						**4.613**	**20.204**

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
EU-3710	VOC Leakage at Tank Farm	lt liq valves	1150	0.024	84.3%	0.433	18.979
		flanges	4400	0.00056	76.4%	0.582	2.547
		lt liq pumps	40	0.25	89.4%	1.060	4.643
TOTALS						**5.975**	**26.169**

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	lb/hr	TPY
EU-3711B	VOC Leakage at Asphalt	hvy liq valves	600	0.0005	0.300	1.314
		flanges	2600	0.00056	1.456	6.377
TOTALS					**1.756**	**7.691**

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	lb/hr	TPY
EU-3732B	VOC Leakage at No. 1 Crude Unit	lt liq valves	250	0.024	6.000	26.280
		hvy liq valves	800	0.0005	0.400	1.752
		flanges	1200	0.00056	0.672	2.943
		lt liq pumps	10	0.25	2.500	10.950
		hvy liq pumps	35	0.046	1.610	7.052
TOTALS					**11.182**	**48.977**

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	lb/hr	TPY
EU-3734B	VOC Leakage at CCR Plat Area	hvy liq pumps	5	0.046	0.230	1.007
TOTALS					**0.230**	**1.007**

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	lb/hr	TPY
EU-3735B	VOC Leakage at Alkylation Unit	open-ended lines	40	0.024	0.960	4.205
		hvy liq pumps	10	0.046	0.460	2.015
		flanges	2000	0.00056	1.120	4.906
		relief valves	35	0.046	1.610	7.052
TOTALS					**4.150**	**18.177**

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	lb/hr	TPY
EU-3711C	VOC Leakage at Asphalt Unit	hvy liq valves	200	0.000873	0.175	0.765
		hvy liq pumps	25	0.016801	0.420	1.840
		hvy liq flanges	600	0.001307	0.784	3.435
TOTALS					**1.379**	**6.039**

EUG 35 - Fugitive Emissions Subject to Monitoring Requirements (40 CFR Part 63 Subpart CC and/or NSPS Subpart GGG)

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	VOC	
						lb/hr	TPY
EU-3740C	VOC Leakage at New Amine Treating Unit, Sour Water Stripper, Sulfur Recovery Unit, and Tail Gas Treating Unit	gas valves	150	0.0177	98.2%	0.048	0.209
		lt liquid valves	100	0.024	84.3%	0.377	1.650
		hvy liq valves	25	0.0005	0%	0.013	0.055
		flanges	1500	0.00056	76.4%	0.198	0.868
		lt liq pumps	10	0.25	89.4%	0.265	1.161
		hvy liq pumps	15	0.046	35.3%	0.446	1.955
TOTALS						**1.347**	**5.899**

EUG 36 - Steam Boilers Subject to NSPS Part 60 Subpart Dc and NSPS Subpart J and MACT Part 63 Subpart DDDDD

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
40-H1101	Indeck steam boiler	0.83	3.53	2.33	10.19	5.43	23.78	0.60	2.62	9.12	39.95
40-HPB1	Holman package boiler	0.58	2.56	1.48	6.48	7.68	33.63	0.42	1.85	6.45	28.25
40-WPB1	Wabash package boiler	0.82	3.57	2.11	9.25	11.04	48.36	0.60	2.65	9.22	40.37
TOTALS		**2.23**	**9.66**	**5.92**	**25.92**	**24.15**	**105.77**	**1.62**	**7.12**	**24.79**	**108.57**

EUG 37 – Fuel Gas Combustion Devices Subject to NSPS Part 60 Subpart Ja and MACT Part 63 Subpart DDDDD

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-GHH2601	GHDS Splitter Reboiler	0.35	1.55	1.60	2.53	2.85	12.49	0.26	1.12	3.91	17.14
P-GHH2602	GHDS Reactor Heater	0.13	0.55	0.56	0.89	1.01	4.42	0.09	0.40	1.38	6.06
P-GHH2603	GHDS Stabilizer Reboiler	0.13	0.55	0.56	0.89	1.01	4.42	0.09	0.40	1.38	6.06
REFORMER	Hydrogen Plant Reformer	0.76	3.01	0.13	0.53	7.44	29.63	0.32	1.26	3.78	15.03
TOTALS		**1.37**	**5.66**	**2.85**	**4.84**	**12.31**	**50.96**	**0.76**	**3.18**	**10.45**	**44.29**

EUG 38 - Fuel Gas Combustion Devices, Subject to NSPS Subpart J and 40 CFR 63 Subpart DDDDD

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-VH101	Vacuum charge heater	0.49	2.15	2.21	9.68	3.96	17.34	0.36	1.56	5.44	23.81
P-DHH801	Hydrotreater charge heater	0.23	1.02	1.04	4.57	1.87	8.18	0.17	0.73	2.56	11.22
P-DHH802	Fractionator charge heater	0.37	1.61	1.65	7.22	2.95	12.93	0.26	1.16	4.05	17.15
P-H356	CCR charge heater	0.22	0.98	1.00	4.40	1.80	7.88	0.16	0.71	2.47	10.82
P-JH301	Fractionator charge heater	0.30	1.31	1.34	5.87	2.40	10.51	0.21	0.94	3.29	14.43
P-CH151	Crude charge heater	0.51	2.24	1.64	7.18	3.74	16.39	0.37	1.62	5.65	24.75
TOTALS		**2.12**	**9.31**	**8.88**	**38.92**	**16.72**	**73.23**	**1.53**	**6.72**	**23.46**	**102.2**

EUG 39 - Fuel Gas Combustion Device, Subject to 40 CFR 63 Subpart LLLLL

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-F1301	Asphalt oxidizer incinerator*	0.13	0.56	15.37	67.61	1.65	7.21	0.09	0.40	1.41	6.18

* includes VOC from Asphalt Unit.

EUG 40 - Grandfathered Fuel Gas Combustion Devices, Subject to MACT Part 63 Subpart DDDDD

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-CH1	Crude fractionation heater	0.73	3.20	9.10	39.88	9.60	42.05	0.53	2.31	8.06	35.32
P-CH2	Crude charge heater	0.38	1.68	4.78	20.94	5.04	22.08	0.28	1.21	4.23	18.54
P-CH3	Crude preflash reboiler	0.27	1.17	3.32	14.54	3.50	15.33	0.19	0.84	2.94	12.88
P-CH121	Vacuum charge heater	0.30	1.32	3.76	16.46	3.96	17.34	0.22	0.95	3.33	14.57
P-JH1	Hydrocracker reactor heater	0.14	0.61	1.75	7.67	1.84	8.06	0.10	0.44	1.55	6.77
P-JH2	Hydrocracker reactor heater	0.14	0.61	1.75	7.67	1.84	8.06	0.10	0.44	1.55	6.77
P-JH101	Hydrocracker fractionator	0.28	1.22	3.49	15.29	3.68	16.12	0.20	0.89	3.09	13.54
P-KH1	Hydrogen reforming heater	0.51	2.21	6.31	27.63	6.65	29.13	0.37	1.60	5.59	24.47
P-PH3	Unifiner stripper reboiler	0.31	1.37	3.90	17.08	4.12	18.05	0.23	0.99	3.46	15.16
P-HH1	Hysomer heater	0.12	0.53	1.50	6.57	1.58	6.92	0.09	0.38	1.33	5.81
P-H152	No. 2 splitter reboiler	0.10	0.42	1.18	5.17	1.25	5.48	0.07	0.30	1.05	4.60
P-5H1	Alkylation repropanizer	0.64	2.80	113.0	495.0	8.41	36.84	0.46	2.03	7.06	30.94
P-H1302	Tank 101 heater	0.08	0.33	0.95	4.16	1.00	4.38	0.06	0.24	0.84	3.68
P-H1303	Tank 101 heater	0.12	0.53	1.51	6.61	1.59	6.96	0.09	0.38	1.34	5.85
P-HT120	Tank 120 heater	0.01	0.03	0.09	0.42	0.10	0.44	0.01	0.02	0.08	0.37
P-HT265	Tank 265 heater	0.01	0.03	0.09	0.42	0.10	0.44	0.01	0.02	0.08	0.37
P-HT601	Tank 601 heater	0.01	0.02	0.07	0.29	0.07	0.31	0.01	0.02	0.06	0.26
P-HT1321	Tank 1321 heater	0.01	0.02	0.07	0.29	0.07	0.31	0.01	0.02	0.06	0.26
P-HT1323	Tank 1323 heater	0.01	0.02	0.07	0.31	0.07	0.31	0.01	0.02	0.06	0.26
P-HT1324	Tank 1324 heater	0.04	0.17	0.47	2.08	0.50	2.19	0.03	0.12	0.42	1.84
	TOTALS	**4.1**	**18.29**	**157.1**	**688.4**	**54.97**	**240.8**	**3.07**	**13.22**	**46.18**	**202.2**

EUG 41 - Fuel Gas Combustion Devices Subject to Oklahoma Rules and MACT Part 63 Subpart DDDDD

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-1B8	Wickes steam boiler	0.96	3.78	10.76	47.13	25.20	99.34	0.69	2.72	10.58	41.71

The applicant elected to take a limit on operations of this unit rather than have NOx emissions exceed 100 TPY.

EUG 42 – Fuel Gas Combustion Devices Subject to NSPS Part 60 Subpart J and MACT Part 63 Subpart DDDDD

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-H350	CCR charge heaters	0.98	4.29	3.40	14.88	12.87	56.36	0.71	3.45	10.81	47.35
P-PH5	Unifiner charge heater	0.24	1.04	0.76	3.33	3.12	13.68	0.17	0.75	2.62	11.49
P-H601	ROSE heater	0.31	1.34	0.98	4.30	2.01	8.82	0.22	0.97	3.38	14.82
P-H1301	Tank 107 heater	0.02	0.09	0.07	0.33	0.28	1.24	0.02	0.07	0.24	1.04
P-1H4	FCCU Feed preheater	0.82	3.60	2.86	12.51	21.63	94.75	0.59	2.61	9.09	39.79
P-SB#4R	Nebraska Package Boiler	0.81	3.53	2.58	11.31	10.60	46.43	0.58	2.55	8.90	39.00
	TOTALS	**3.18**	**13.89**	**10.65**	**46.66**	**50.51**	**221.28**	**2.29**	**10.40**	**35.04**	**153.49**

EUG 43 – Asphalt Unit Heater, Subject to MACT Part 63 Subpart DDDDD

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-H1331	Asphalt Unit hot oil heater	0.06	0.28	0.01	0.02	0.84	3.68	0.05	0.20	0.71	3.09

EUG 44 - Fuel Gas Combustion Devices Subject to NSPS Part 60 Subpart J and MACT Part 63 Subpart DDDDD

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-H48001	SRU Hot Oil Heater	0.59	2.59	1.77	7.76	7.80	34.19	0.43	1.88	6.55	28.72
P-HT134	Tank 134 heater	0.06	0.28	0.28	1.23	0.84	3.68	0.05	0.20	0.71	3.09
P-HT136	Tank 136 heater	0.06	0.28	0.28	1.23	0.84	3.68	0.05	0.20	0.71	3.09
P-HT264	Tank 264 heater	0.01	0.03	0.03	0.15	0.10	0.45	0.05	0.20	0.71	3.09
TOTALS		**0.72**	**3.18**	**2.36**	**10.37**	**9.58**	**42.00**	**0.58**	**2.48**	**8.68**	**37.99**

EUG 45 – Flares, Subject to 40 CFR Part 60 Subpart Ja [1]

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-FS1451	John Zink EEF-QS-12	0.43	1.90	30.26	132.5	21.26	93.13	0.90	3.94	4.84	21.19
P-FS1403	West Flare	0.86	3.80	60.52	256.0	42.52	186.3	1.80	7.92	72.82	42.38
P-FS1503	Hydrocracker Flare	0.01	0.01	0.01	0.01	0.02	0.09	0.03	0.13	0.07	0.32
TOTALS		**1.30**	**5.71**	**90.79**	**397.6**	**63.80**	**279.5**	**2.73**	**11.95**	**77.73**	**63.89**

[1] All emissions represented in this table are estimates only and do not represent permit limitations. There are no SO_2 emission increases related to the Hydrocracker Project.

EUG 46 – Fuel Gas Combustion Devices Subject to NSPS Part 60 Subpart Ja and MACT Part 63 Subpart DDDDD

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
52-H01	BenFree Unit Heater	0.25	1.08	2.18	3.54	2.28	9.96	1.69	7.39	2.44	10.68

EUG 51 – Miscellaneous Process Vent

Point	Process	VOC	
		lb/hr	TPY
P-VENT7	Asphalt light ends recovery sump	0.91	3.99

EUG 53 – Process Vents Subject to Permit Limitations and 40 CFR Part 63 Subpart UUU

Point	Process	VOC	
		lb/hr	TPY
P-VENT6	CCR regenerator vent	2.20	9.63

EUG 54 – Molten Sulfur Pit

EU	Point	Normal Contents	H_2S	
			lb/hr	TPY
P-SP301	P-SP301	Sulfur	0.014	0.06

EUG 56 – Grandfathered Wastewater System Subject to 40 CFR Part 63 Subpart CC

Point	Process	VOC	
		lb/hr	TPY
P-WW1	Process wastewater systems and open sewers	10.20	44.67

EUG 57 – Wastewater Systems Subject to NSPS Subpart QQQ and 40 CFR Part 63 Subpart CC

Point	Process	VOC	
		lb/hr	TPY
EU-WW2	CCR drain	0.035	0.153
	D-208 drain	0.035	0.153
	S-1450 drain	0.035	0.153
	S-1451 drain	0.035	0.153
TOTALS		**0.140**	**0.612**

EUG 58 – Open API Separator

Point	Process	VOC	
		lb/hr	TPY
P-API1	Open API Separator	110.82	485.40

EUG 59 – Covered API Separator Subject to NSPS Part 60 Subpart QQQ

Point	Process	VOC	
		lb/hr	TPY
P-API2	Covered API Separator	0.60	2.63

EUG 60 – Wastewater Systems Subject to NSPS Subpart QQQ and 40 CFR Part 63 Subpart CC in SRU, Diesel Hydrodesulfurization Area, Vacuum Unit 2 Area, GHDS Unit, Benfree Unit, and Hydrogen Plant Reformer

EU	Point	Equipment	VOC	
			lb/hr	TPY
EU-WW3	EU-WW3	SRU Closed Process Drains	0.88	3.83
		SRU Closed Junction Boxes	0.14	0.61
EU-WW4	EU-WW4	DHDU P-trap Drains	0.88	3.83
		DHDU Junction Boxes	0.14	0.61
EU-WW5	EU-WW5	P-trap Drains	0.88	3.83
		Junction Boxes	0.14	0.61
EU-WW6	EU-WW6	10 P-trap Drains	0.35	1.53
		2 Junction Boxes	0.14	0.61
EU-52WW	EU-52WW	25 Drains	0.88	3.83
EU-53WW	EU-53WW	5 Drains	0.21	0.92
TOTALS			**4.64**	**20.21**

EUG 61 – Benfree Unit Oil-Water Separator Subject to 40 CFR 60 Subpart QQQ and 40 CFR 63 Subpart CC

EU	Point	Equipment	VOC	
			lb/hr	TPY
52-T01	52-T01	Benfree Unit Separator	0.85	3.73

EUG 64 – GHDS Oil-Water Separator Subject to NSPS QQQ and 40 CFR 63, Subpart CC

Point	Process	VOC	
		lb/hr	TPY
P-API3	GHDS Oil-Water Separator	2.99	1.11

EUG 66 – Cooling Towers

Point	Process	VOC	
		lb/hr	TPY
P-CWT1	Crude Unit cooling tower	5.40	23.65
P-CWT3	FCCU cooling tower	3.96	17.34
P-CWT5	Alky Unit cooling tower	1.62	7.10
TOTALS		**10.98**	**48.09**

The vacuum unit cooling tower (P-CWT2) was eliminated.

EUG 67 – Hydrocracker Cooling Tower

EU	Point	Equipment	VOC		PM	
			lb/hr	TPY	lb/hr	TPY
P-CWT4	P-CWT4	Hydrocracker Cooling Tower	0.34	1.47	0.11	0.48

EUG 68 – GHDS Unit and Benfree Unit Cooling Towers Subject to 40 CFR 63 Subpart CC

EU	Point	Equipment	VOC		PM	
			lb/hr	TPY	lb/hr	TPY
P-CWT6	P-CWT6	GHDS Unit Cooling Tower	0.25	1.10	0.08	0.36
52-CT	52-CT	Benfree Unit Cooling Tower	0.05	0.22	0.13	0.58
TOTALS			**0.30**	**1.32**	**0.21**	**0.94**

EUG 80 – Non-gasoline Loading Racks

Point	Process	VOC	
		lb/hr	TPY
P-LR2T	Gas oil truck unloading rack	3.48	0.87
P-LT2R	Gas oil rail unloading rack	3.48	0.87
P-LR3T	Solvent truck loading rack	65.76	1.15
P-LT3R	Solvent rail loading rack	64.68	3.81
P-LR5T	Asphalt truck loading rack	9.84	9.20
P-LR5R	Asphalt/slurry rail loading rack	17.84	0.08
P-LR6T	Slurry truck loading rack	0.01	0.01
TOTALS		**165.11**	**16.01**

EUG 81 – New Non-gasoline Loading Rack

Point	Process	VOC	
		lb/hr	TPY
P-LR4T	JP-8 truck loading rack	0.47	0.24

EUG 82 – Molten Sulfur Loading Racks

EU	Point	Equipment	H_2S	
			lb/hr	TPY
P-SLRR	P-SLRR	Sulfur railcar loading rack	0.014	0.06
P-SLRT	P-SLRT	Sulfur truck loading rack	0.014	0.06
TOTALS			0.028	0.12

EUG 85 – FCCU Regenerator Subject to NSPS Subpart J

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-1ME258	FCCU regenerator	15.4	67.5	437.4	1916.0	62.1	272.2	3.67	16.06	9.52	41.7

EUG 87 - SRU Tail Gas Incinerator Subject to NSPS Subpart J and 40 CFR Part 63 Subpart UUU

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-TGIS1	Sulfur Recovery Unit	0.22	1.00	18.90	82.77	3.01	13.20	0.17	0.73	7.14	31.27

EUG 90 – Miscellaneous Insignificant Heaters

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
IH-1	Kyle House	0.01	0.01	0.01	0.01	0.01	0.04	0.01	0.01	0.01	0.04
IH-2	Main Office	0.01	0.01	0.01	0.04	0.04	0.16	0.01	0.01	0.03	0.14
IH-3	Webb House	0.01	0.01	0.01	0.01	0.01	0.04	0.01	0.01	0.01	0.04
IH-4	Laboratory	0.01	0.01	0.01	0.02	0.02	0.08	0.01	0.01	0.02	0.07
IH-5	Laboratory	0.01	0.01	0.01	0.01	0.01	0.04	0.01	0.01	0.01	0.04
IH-6	Laboratory	0.01	0.01	0.01	0.02	0.02	0.07	0.01	0.01	0.01	0.06
IH-7	Laboratory	0.01	0.01	0.01	0.02	0.02	0.07	0.01	0.01	0.01	0.06
IH-8	Laboratory	0.01	0.01	0.01	0.02	0.02	0.07	0.01	0.01	0.01	0.06
IH-9	Laboratory	0.01	0.01	0.01	0.02	0.02	0.07	0.01	0.01	0.01	0.06
IH-10	Electrical Shop	0.01	0.01	0.01	0.02	0.02	0.08	0.01	0.01	0.02	0.07
IH-11	Maintenance Office	0.01	0.01	0.01	0.01	0.01	0.06	0.01	0.01	0.01	0.06
IH-12	Maintenance Office	0.01	0.01	0.01	0.02	0.02	0.07	0.01	0.01	0.01	0.05
IH-13	East Shop	0.02	0.07	0.05	0.23	0.23	0.99	0.01	0.05	0.19	0.83
IH-14	West Shop	0.02	0.07	0.06	0.28	0.23	0.99	0.01	0.05	0.19	0.83
TOTALS		**0.16**	**0.26**	**0.23**	**0.73**	**0.68**	**2.83**	**0.14**	**0.22**	**0.54**	**2.41**

EUG 91 - Miscellaneous Engines

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
IE-1	Wastewater Plant	0.66	0.16	0.62	0.15	9.30	2.32	0.74	0.19	2.00	0.50
IE-2	Portable Generator	0.01	0.01	0.01	0.01	0.06	0.02	0.08	0.02	2.20	0.55
IE-3	Portable Generator	0.01	0.01	0.01	0.01	0.09	0.02	0.12	0.03	3.51	0.88
P-1183	Cummins NT 855-F4	0.75	0.04	0.70	0.03	10.54	0.53	0.85	0.04	2.27	0.11
P-1184	Caterpillar 3406B	0.83	0.04	0.77	0.04	11.63	0.58	0.94	0.05	2.51	0.13
P-1185	Cummins QSM11	0.88	0.04	0.82	0.04	12.40	0.62	1.00	0.05	2.67	0.13
TOTALS		**3.14**	**0.30**	**2.93**	**0.28**	**44.02**	**4.09**	**3.73**	**0.38**	**15.16**	**2.30**

EUG 92 - Miscellaneous Insignificant Tanks

Point ID	Location	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
IT-1	Shop	--	--	--	--	--	--	0.01	0.01	--	--
IT-2	Shop	--	--	--	--	--	--	0.01	0.01	--	--
IT-3	FCCU	--	--	--	--	--	--	0.01	0.01	--	--
IT-4	Platformer	--	--	--	--	--	--	0.01	0.01	--	--
IT-5	FCCU	--	--	--	--	--	--	0.01	0.01	--	--
T-1417	Truck rack	--	--	--	--	--	--	0.01	0.01	--	--
IT-7	#2 Crude Unit	--	--	--	--	--	--	0.01	0.01	--	--
IT-8	#2 Crude Unit	--	--	--	--	--	--	0.01	0.01	--	--
IT-9	FCCU	--	--	--	--	--	--	0.01	0.01	--	--
IT-10	FCCU	--	--	--	--	--	--	0.01	0.01	--	--
IT-11	#1 Crude Unit	--	--	--	--	--	--	0.01	0.01	--	--
IT-13	72 Manifold	--	--	--	--	--	--	0.01	0.01	--	--
T-1414	Truck rack	--	--	--	--	--	--	0.01	0.01	--	--

Point ID	Location	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
T-1416	Truck rack	--	--	--	--	--	--	0.01	0.01	--	--
IT-17	Crude Vacuum Unit	--	--	--	--	--	--	0.01	0.01	--	--
IT-18	Hydrocracker	--	--	--	--	--	--	0.01	0.01	--	--
IT-20	Boilerhouse	--	--	--	--	--	--	0.01	0.01	--	--
IT-21	FCCU	--	--	--	--	--	--	0.01	0.01	--	--
IT-22	Lt. Oils Blender	--	--	--	--	--	--	0.01	0.01	--	--
IT-23	FCCU	--	--	--	--	--	--	0.01	0.01	--	--
IT-24	#1 Crude Unit	--	--	--	--	--	--	0.01	0.01	--	--
IT-25	#1 Crude Unit	--	--	--	--	--	--	0.01	0.01	--	--
IT-26	#2 Crude Unit	--	--	--	--	--	--	0.01	0.01	--	--
IT-27	#2 Crude Unit	--	--	--	--	--	--	0.01	0.01	--	--
IT-28	72 Manifold	--	--	--	--	--	--	0.01	0.01	--	--
IT-29	#1 Crude Unit	--	--	--	--	--	--	0.01	0.01	--	--
IT-30	#2 Crude Unit	--	--	--	--	--	--	0.01	0.01	--	--
T-1476	Truck Rack	--	--	--	--	--	--	0.01	0.01	--	--
IT-31	#2 Crude Unit	--	--	--	--	--	--	0.01	0.01	--	--
IT-32	Platformer	--	--	--	--	--	--	0.01	0.01	--	--
IT-33	Alky Unit	--	--	--	--	--	--	0.01	0.01	--	--
IT-34	FCCU	--	--	--	--	--	--	0.01	0.01	--	--
IT-35	72 Manifold	--	--	--	--	--	--	0.01	0.01	--	--
IT-36	FCCU	--	--	--	--	--	--	0.01	0.01	--	--
IT-37	Products Handling	--	--	--	--	--	--	0.01	0.01	--	--
T-1424	JP-8 Rack	--	--	--	--	--	--	0.01	0.01	--	--
T-1413	Truck rack	--	--	--	--	--	--	0.01	0.01	--	--
IT-40	FCCU	--	--	--	--	--	--	0.01	0.01	--	--
IT-41	#1 Crude Unit	--	--	--	--	--	--	0.01	0.01	--	--
IT-42	#2 Crude Unit	--	--	--	--	--	--	0.01	0.01	--	--
IT-43	FCCU	--	--	--	--	--	--	0.01	0.01	--	--
IT-44	Alky Unit	--	--	--	--	--	--	0.01	0.01	--	--
IT-45	#1 Crude Unit	--	--	--	--	--	--	0.01	0.01	--	--
T-1418	Truck rack	--	--	--	--	--	--	0.01	0.01	--	--
T-6092	72 Manifold	--	--	--	--	--	--	0.01	0.01	--	--
T-1426	Truck rack	--	--	--	--	--	--	0.01	0.01	--	--
T-1425	near T-1475	--	--	--	--	--	--	0.01	0.01	--	--
T-1486	near T-201	--	--	--	--	--	--	0.01	0.01	--	--
P-T141	Diesel blending	--	--	--	--	--	--	0.01	0.01	--	--
P-T1424	Diesel blending	--	--	--	--	--	--	0.01	0.01	--	--
P-T1425	Diesel blending	--	--	--	--	--	--	0.01	0.01	--	--
P-T1486	Diesel blending	--	--	--	--	--	--	0.01	0.01	--	--
P-T2001	Asphalt blending	--	--	--	--	--	--	0.81	1.76	--	--
P-T2002	Asphalt blending	--	--	--	--	--	--	0.18	0.40	--	--
TOTALS		**--**	**--**	**--**	**--**	**--**	**--**	**1.52**	**2.69**	**--**	**--**

EUG 93 – Miscellaneous Insignificant Process Vents

Unit ID	Description	VOC	
		lb/hr	TPY
DAVENT	Reformer Deaerator Vent	1.06	3.15
BDVENT	Reformer Blowdown Vent	1.38	1.23
PSA Hydrogen	Reformer PSA Hydrogen Vent	--	--
TOTALS		**2.44**	**4.38**

SUMMARY OF POTENTIAL AIR EMISSIONS

Point No.	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-CH1	Crude fractionation	0.73	3.20	9.10	39.88	9.60	42.05	0.53	2.31	8.06	35.32
P-CH2	Crude charge heater	0.38	1.68	4.78	20.94	5.04	22.08	0.28	1.21	4.23	18.54
P-CH3	Crude preflash reboiler	0.27	1.17	3.32	14.54	3.50	15.33	0.19	0.84	2.94	12.88
P-CH151	Crude charge heater	0.51	2.24	1.64	7.18	3.74	16.39	0.37	1.62	5.65	24.75
P-CH121	Vacuum charge heater	0.30	1.32	3.76	16.46	3.96	17.34	0.22	0.95	3.33	14.57
P-JH1	Hydrocracker reactor	0.14	0.61	1.75	7.67	1.84	8.06	0.10	0.44	1.55	6.77
P-JH2	Hydrocracker reactor	0.14	0.61	1.75	7.67	1.84	8.06	0.10	0.44	1.55	6.77
P-JH101	Hydrocracker	0.28	1.22	3.49	15.29	3.68	16.12	0.20	0.89	3.09	13.54
P-KH1	Hydrogen reforming	0.51	2.21	6.31	27.63	6.65	29.13	0.37	1.60	5.59	24.47
P-PH3	Unifiner stripper reboiler	0.31	1.37	3.90	17.08	4.12	18.05	0.23	0.99	3.46	15.16
P-HH1	Hysomer heater	0.12	0.53	1.50	6.57	1.58	6.92	0.09	0.38	1.33	5.81
P-H152	No. 2 splitter reboiler	0.10	0.42	1.18	5.17	1.25	5.48	0.07	0.30	1.05	4.60
P-5H1	Alky Heater	0.64	2.80	113.02	495.03	8.41	36.84	0.46	2.03	7.06	30.94
P-F1301	Asphalt oxidizer	0.13	0.56	15.37	67.61	1.68	7.21	0.09	0.40	1.41	6.18
40-H1101	Indeck steam boiler	0.83	3.61	2.33	10.19	5.43	23.78	0.60	2.62	9.12	39.95
P-1B8	Wickes steam boiler	0.96	3.78	10.76	47.132	25.20	99.34	0.69	2.72	10.58	41.71
P-H1302	Tank 101 heater	0.08	0.33	0.95	4.16	1.00	4.38	0.06	0.24	0.84	3.68
P-H1303	Tank 101 heater	0.12	0.53	1.51	6.61	1.59	6.96	0.09	0.38	1.34	5.85
P-HT120	Tank 120 heater	0.01	0.03	0.09	0.42	0.10	0.44	0.01	0.02	0.08	0.37
P-HT265	Tank 265 heater	0.01	0.03	0.09	0.42	0.10	0.44	0.01	0.02	0.08	0.37
P-HT601	Tank 601 heater	0.01	0.02	0.07	0.29	0.07	0.31	0.00	0.02	0.06	0.26
P-HT1321	Tank 1321 heater	0.01	0.02	0.07	0.29	0.07	0.31	0.00	0.02	0.06	0.26
P-HT1323	Tank 1323 heater	0.01	0.02	0.07	0.31	0.07	0.31	0.00	0.02	0.06	0.26
P-HT1324	Tank 1324 heater	0.04	0.17	0.47	2.08	0.50	2.19	0.03	0.12	0.42	1.84
P-1H4	FCCU Feed preheater	0.82	3.60	2.86	12.51	**21.63**	94.75	0.59	2.61	9.09	39.79
P-SB#4R	Nebraska Package	0.81	3.53	2.58	11.31	10.60	46.43	0.58	2.55	8.90	39.00
P-H350	CCR charge heaters	0.98	4.29	3.40	14.88	12.87	56.36	0.71	3.45	10.81	47.35
P-PH5	Unifiner charge heater	0.24	1.04	0.76	3.33	3.12	13.68	0.17	0.75	2.62	11.49
P-H601	ROSE heater	0.31	1.34	0.98	4.30	2.01	8.82	0.22	0.97	3.38	14.82
P-H1301	Tank 107 heater	0.02	0.09	0.08	0.33	0.28	1.24	0.02	0.07	0.24	1.04
P-HT134	Tank 134 heater	0.06	0.28	0.28	1.23	0.84	3.68	0.05	0.20	0.71	3.09
P-HT136	Tank 136 heater	0.06	0.28	0.22	0.97	0.84	3.68	0.05	0.20	0.71	3.09
P-HT264	Tank 264 heater	0.01	0.03	0.03	0.15	0.10	0.45	0.05	0.20	0.71	3.09
P-FS1451	South flare	0.43	1.90	30.26	132.54	21.26	93.13	0.90	3.94	4.84	21.19

SUMMARY OF POTENTIAL AIR EMISSIONS - Continued

Point No.	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-1ME258	FCCU Regenerator	15.4	67.5	437.40	1916.0	62.14	272.17	3.67	16.06	9.52	41.70
P-T101	Tank 101	--	--	--	--	--	--	0.25	1.11	--	--
P-T107	Tank 107	--	--	--	--	--	--	0.16	0.69	--	--
P-T108	Tank 108	--	--	--	--	--	--	0.07	0.17	--	--
P-T110	Tank 110	--	--	--	--	--	--	0.29	0.54	--	--
P-T111	Tank 111	--	--	--	--	--	--	0.03	0.05	--	--
P-T120	Tank 120	--	--	--	--	--	--	0.01	0.04	--	--
P-T126	Tank 126	--	--	--	--	--	--	0.01	0.01	--	--
P-T1321	Tank 1321	--	--	--	--	--	--	11.02	24.14	--	--
P-T1323	Tank 1323	--	--	--	--	--	--	11.26	24.66	--	--
P-T1324	Tank 1324	--	--	--	--	--	--	0.204	0.87	--	--
P-T134	Tank 134	--	--	--	--	--	--	0.06	0.24	--	--
P-T136	Tank 136	--	--	--	--	--	--	0.11	0.19	--	--
P-T138	Tank 138	--	--	--	--	--	--	2.38	10.42	--	--
P-T140	Tank 140	--	--	--	--	--	--	2.41	10.54	--	--
P-T142	Tank 142	--	--	--	--	--	--	6.58	28.80	--	--
P-T143	Tank 143	--	--	--	--	--	--	6.6	28.92	--	--
P-T144	Tank 144	--	--	--	--	--	--	6.6	28.91	--	--
P-T1441	Tank 1441	--	--	--	--	--	--	0.43	0.43	--	--
P-T1449	Tank 1449	--	--	--	--	--	--	13.75	30.11	--	--
P-T146	Tank 146	--	--	--	--	--	--	2.38	8.94	--	--
P-T147	Tank 147	--	--	--	--	--	--	1.68	7.34	--	--
P-T1470	Tank 1470	--	--	--	--	--	--	6.53	28.60	--	--
P-T1471	Tank 1471	--	--	--	--	--	--	1.17	3.21	--	--
P-T1472	Tank 1472	--	--	--	--	--	--	0.44	0.74	--	--
P-T1473	Tank 1473	--	--	--	--	--	--	3.44	7.54	--	--
P-T1474	Tank 1474	--	--	--	--	--	--	.73	1.61	--	--
P-T1475	Tank 1475	--	--	--	--	--	--	.17	.74	--	--
P-T1476	Tank 1476	--	--	--	--	--	--	0.01	0.02	--	--
P-T148	Tank 148	--	--	--	--	--	--	3.73	16.33	--	--
P-T150	Tank 150	--	--	--	--	--	--	2.4	10.53	--	--
P-T152	Tank 152	--	--	--	--	--	--	3.46	10.09	--	--
P-T154	Tank 154	--	--	--	--	--	--	3.89	8.61	--	--
P-T162	Tank 162	--	--	--	--	--	--	0.01	0.01	--	--
P-T164	Tank 164	--	--	--	--	--	--	2.8411	8.76	--	--
P-T168	Tank 168	--	--	--	--	--	--	2.0	8.76	--	--
P-T1901	Tank 1901	--	--	--	--	--	--	0.01	0.01	--	--
P-T2001	Tank 2001	--	--	--	--	--	--	0.81	1.761	--	--
P-T2002	Tank 2002	--	--	--	--	--	--	0.18	0.4	--	--
P-T202	Tank 202	--	--	--	--	--	--	0.01	0.01	--	--
P-T2052	Tank 2052	--	--	--	--	--	--	0.1	0.1	--	--
P-T67	Tank 67	--	--	--	--	--	--	3.83	8.38	--	--
P-T68	Tank 68	--	--	--	--	--	--	3.83	8.38	--	--
P-T69	Tank 69	--	--	--	--	--	--	3.83	8.38	--	--
P-T250	Tank 250	--	--	--	--	--	--	0.03	0.11	--	--

SUMMARY OF POTENTIAL AIR EMISSIONS - Continued

Point No.	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-T251	Tank 251	--	--	--	--	--	--	0.43	1.88	--	--
P-T252	Tank 252	--	--	--	--	--	--	0.01	0.01	--	--
P-T253	Tank 253	--	--	--	--	--	--	0.10	0.24	--	--
P-T254	Tank 254	--	--	--	--	--	--	1.14	5.00	--	--
P-T255	Tank 255	--	--	--	--	--	--	1.883	8.24	--	--
P-T256	Tank 256	--	--	--	--	--	--	0.02	0.05	--	--
P-T257	Tank 257	--	--	--	--	--	--	0.04	0.17	--	--
P-T262	Tank 262	--	--	--	--	--	--	0.11	0.14	--	--
P-T263	Tank 263	--	--	--	--	--	--	0.01	0.05	--	--
P-T264	Tank 264	--	--	--	--	--	--	8.34	18.28	--	--
P-T265	Tank 265	--	--	--	--	--	--	0.32	1.39	--	--
P-T266	Tank 266	--	--	--	--	--	--	0.71	1.55	--	--
P-T269	Tank 269	--	--	--	--	--	--	0.01	0.04	--	--
P-T303	Tank 303	--	--	--	--	--	--	14.41	31.55	--	--
P-T501	Tank 501	--	--	--	--	--	--	5.76	12.62	--	--
P-T601	Tank 601	--	--	--	--	--	--	8.07	17.32	--	--
P-VENT6	CCR Regenerator vent	--	--	--	--	--	--	2.20	9.63	--	--
P-VENT7	Asphalt light ends	--	--	--	--	--	--	0.91	3.99	--	--
P-LR2T	Gas Oil truck loading	--	--	--	--	--	--	3.48	0.87	--	--
P-LT2R	Gas Oil rail unloading	--	--	--	--	--	--	3.48	0.87	--	--
P-LR3T	Solvent truck loading	--	--	--	--	--	--	65.76	1.15	--	--
P-LT3R	Solvent rail loading rack	--	--	--	--	--	--	64.68	3.81	--	--
P-LR4T	JP-8 truck loading rack	--	--	--	--	--	--	0.47	0.24	--	--
P-LR5T	Asphalt truck loading	--	--	--	--	--	--	9.84	9.20	--	--
P-LR5R	Asphalt/slurry truck	--	--	--	--	--	--	17.84	0.08	--	--
P-LR6T	Slurry truck loading rack	--	--	--	--	--	--	0.01	0.01	--	--
P-CWT1	Crude unit cooling twr	--	--	--	--	--	--	5.40	23.65	--	--
P-CWT3	FCCU cooling tower	--	--	--	--	--	--	3.96	17.34	--	--
P-CWT4	Hydrocracker cooling	0.11	0.48	--	--	--	--	0.74	3.23	--	--
P-CWT5	Alky cooling tower	--	--	--	--	--	--	1.62	7.10	--	--
EU-3722A	FCCU	--	--	--	--	--	--	9.52	41.69	--	--
EU-3725A	Hydrocracker	--	--	--	--	--	--	8.51	37.26	--	--
EU-3732A	No. 1 Crude Unit	--	--	--	--	--	--	8.25	36.14	--	--
EU-3733A	No. 2 Crude Unit	--	--	--	--	--	--	9.64	42.24	--	--
EU3734A	CCR Platformer	--	--	--	--	--	--	14.99	65.65	--	--
EU3735A	Alkylation Unit	--	--	--	--	--	--	10.14	44.41	--	--
EU-3736A	Diesel HDT Unit	--	--	--	--	--	--	7.87	34.48	--	--
EU3706A	Loading terminals fug.	--	--	--	--	--	--	2.50	10.95	--	--
EU3740A	SWS, SRU, Amine	--	--	--	--	--	--	6.61	28.94	--	--
EU3711B	Asphalt oxidizer	--	--	--	--	--	--	1.76	7.69	--	--
EU-3732B	No. 1 Crude Unit	--	--	--	--	--	--	11.18	48.98	--	--
P-WW1	Wastewater treating	--	--	--	--	--	--	10.20	44.67	--	--
EU-WW2	Wastewater treating	--	--	--	--	--	--	0.14	.612	--	--
P-API1	Open API separator	--	--	--	--	--	--	110.82	485.40	--	--

SUMMARY OF POTENTIAL AIR EMISSIONS - Continued

Point No.	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-API2	Closed API separator	--	--	--	--	--	--	0.60	2.63	--	--
EUG-90	Misc. insig. heaters	0.16	0.26	0.23	0.73	0.68	2.83	0.14	0.22	0.54	2.41
EUG-91	Misc. insig. engines	0.68	0.18	0.64	0.17	9.45	2.32	0.94	0.24	7.71	1.93
EUG-92	Misc. insig. tanks	--	--	--	--	--	--	0.53	0.53	--	--
P-PLF1	Product loading term.	--	--	--	--	--	--	3.08	12.67		
EU-3734B	CCR Platformer area	--	--	--	--	--	--	0.23	1.01	--	--
P-T1331	Asphalt Unit tank	--	--	--	--	--	--	0.3	0.444	--	--
P-T1332	Asphalt Unit tank	--	--	--	--	--	--	0.3	0.444	--	--
P-T1333	Asphalt Unit tank	--	--	--	--	--	--	0.3	0.444	--	--
P-T1337	Blending tank	--	--	--	--	--	--	0.2	0.301	--	--
P-T1338	Blending tank	--	--	--	--	--	--	0.2	0.301	--	--
P-MP1330	Mill skid	--	--	--	--	--	--	0.2	0.346	--	--
P-T1330	Wetting vessel	--	--	--	--	--	--	0.1	0.080	--	--
P-H1331	Asphalt Unit heater	0.064	0.280	0.005	0.022	0.840	3.679	0.046	0.202	0.706	3.090
T-200	Diesel Tank	--	--	--	--	--	--	0.43	1.90	--	--
T-155	Naphtha Tank	--	--	--	--	--	--	0.38	1.66	--	--
T-70	Crude Oil Tank	--	--	--	--	--	--	1.22	5.31	--	--
P-VH101	Vacuum charge heater	0.49	2.15	2.21	9.68	3.96	17.34	0.36	1.56	5.44	23.81
P-DHH801	Hydrotreater charge	0.23	1.02	1.04	4.57	1.87	8.18	.17	.73	2.56	11.22
P-DHH802	Fractionator charge	0.37	1.61	1.65	7.22	2.95	12.93	.26	1.16	4.05	17.15
P-H356	CCR charge heater	0.22	0.98	1.00	4.40	1.80	7.88	.160	.71	2.47	10.82
P-JH301	Fractionator charge	0.30	1.31	1.34	5.87	2.40	10.51	0.21	.94	3.29	14.43
P-WW4	HDT Wastewater	--	--	--	--	--	--	1.02	4.44	--	--
P-WW5	CVU Wastewater	--	--	--	--	--	--	1.02	4.44	--	--
EU-3711C	Asphalt Unit	--	--	--	--	--	--	1.38	6.04	--	--
EU-3742C	SWS, SRU, TGTU	--	--	--	--	--	--	1.35	5.90	--	--
EU-WW3	SRU, TGTU, Amine	--	--	--	--	--	--	1.02	4.44	--	--
P-FS1403	West Flare	0.86	3.80	60.52	256.0	42.52	186.3	1.80	7.92	72.82	42.38
P-FS1503	Hydrocracker Flare	0.01	0.01	0.01	0.01	0.02	0.09	0.03	0.13	0.07	0.32
P-H48001	SRU hot oil heater	0.59	2.59	1.77	7.76	7.80	34.19	0.43	1.88	6.55	28.72
P-T2051	Sour water / diesel	--	--	--	--	--	--	0.11	0.46	--	--
P-TGIS1	SRU tail gas incin.	0.22	1.00	18.90	82.77	3.01	13.20	0.17	0.73	7.14	31.27
P-T203	T-203	--	--	--	--	--	--	0.87	3.82	--	--
EU-3726A	GHDS Unit	--	--	--	--	--	--	4.63	20.30	--	--
P-GHH2601	GHDS Splitter Reboiler	0.35	1.55	1.60	2.53	2.85	12.49	0.26	1.12	3.91	17.14
P-GHH2602	GHDS Reactor Heater	0.13	0.55	0.56	0.89	1.01	4.42	0.09	0.40	1.38	6.06
P-GHH2603	GHDS Stabilizer	0.13	0.55	0.56	0.89	1.01	4.42	0.09	0.40	1.38	6.06
EU-WW6	GHDS Wastewater	--	--	--	--	--	--	0.49	2.15	--	--
P-API3	GHDS Oil-Water Sep	--	--	--	--	--	--	2.99	1.11	--	--
P-CWT6	GHDS Cooling Tower	0.08	0.36	--	--	--	--	0.25	1.10	--	--
P-1183	Cummins NT 855-F4	0.75	0.04	0.70	0.03	10.54	0.53	0.85	0.04	2.27	0.11
P-1184	Caterpillar 3406B	0.83	0.04	0.77	0.04	11.63	0.58	0.94	0.05	2.51	0.13
P-1185	Cummins QSM11	0.88	0.04	0.82	0.04	12.40	0.62	1.00	0.05	2.67	0.13
EU-3707	LPG Unit	--	--	--	--	--	--	1.82	8.00	--	--
EU-3727	RFG System	--	--	--	--	--	--	4.61	20.20	--	--
EU-3710	Tank Farm VOC Leaks	--	--	--	--	--	--	5.98	26.17	--	--

SUMMARY OF POTENTIAL AIR EMISSIONS - Continued

Point No.	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
40-HPB1	Holman package	0.58	2.56	1.48	6.48	7.68	33.63	0.42	1.85	6.45	28.25
40-WPB1	Wabash package boiler	0.82	3.57	2.11	9.25	11.04	48.36	0.60	2.65	9.22	40.37
EU-3752A	Benfree Unit fugitives	--	--	--	--	--	--	1.88	8.22	--	--
52-T05	Benfree Unit separator	--	--	--	--	--	--	0.85	3.73	--	--
EU-52WW	Benfree Unit drains	--	--	--	--	--	--	0.88	3.83	--	--
EU-53WW	Hydrocracker Ref drains	--	--	--	--	--	--	0.21	0.92	--	--
REFORMER	Hydrogen Plant Reform	0.76	3.01	0.13	0.53	7.44	29.63	0.32	1.26	3.78	15.03
TOTALS		**35.39**	**140.3**	**764.18**	**3318.0**	**369.61**	**1416.0**	**604.13**	**1678.1**	**271.39**	**841.33**

Greenhouse gas emissions were stated at 12,718,338 TPY using the methods of 40 CFR Part 98.

HAZARDOUS AIR POLLUTANTS

HAP	CAS Number	Emissions	
		lb/hr	TPY
Antimony	7440360	0.079	0.303
Benzene	71432	1.755	7.69
Chlorine	7782505	0.033	0.15
Cumene	98828	0.043	0.19
Diethanolamine	111422	0.001	0.01
Ethylbenzene	100414	0.560	2.45
Ethylene	74851	0.533	2.34
Formaldehyde	50000	0.144	0.63
Gasoline (unleaded)	8006619	89.78	166.39
Glycol ethers	--	0.033	0.15
n-Hexane	110543	3.893	17.05
HCl	7647010	0.667	2.92
HF	7664393	0.325	1.43
Nickel	7440020	0.240	1.053
Methanol	67561	0.033	0.82
Molybdenum	7439987	0.033	0.15
Naphthalene	91203	0.064	0.28
Nickel	7440020	0.053	0.23
Propylene	115071	1.736	7.60
Quinoline	91225	0.001	0.01
Tetrachloroethylene	127184	0.033	0.15
Toluene	108883	4.377	19.17
2,2,4-Trimethylpentane	540841	1.168	5.12
Vanadium	7440662	0.405	1.774
Xylene	1330207	3.643	15.96

The primary discharge points for air emissions at the facility are tabulated as follows.

SIGNIFICANT DISCHARGE POINTS

Point ID	Description	Height Feet	Diameter Inches	Flow Rate ACFM	Temp. ºF
P-CH1	Crude fractionation heater (2 stacks)	63	52	48950	880
P-CH2	Crude charge heater (2 stacks)	75	39	22247	700
P-CH3	Crude preflash reboiler	67	54	13813	640
P-CH151	Crude charge heater	130	68	25290	490
P-CH121	Vacuum charge heater (2 stacks)	81	33	20192	880
P-VH101	Vacuum charge heater	57	42	17778	1000
P-JH1	Hydrocracker reactor heater	100	48	9190	900
P-JH101	Hydrocracker fractionator reboiler	100	48	15780	720
P-KH1	Hydrogen reforming heater	165	58	26823	600
P-PH3	Unifiner stripper reboiler	49	42	23180	1020
P-HH1	Hysomer heater	49	36	5291	420
P-H152	No. 2 splitter reboiler	71	42	4994	590
P-5H1	Alkylation repropanizer reboiler	131	54	39052	760
P-F1301	Asphalt oxidizer incinerator	101	41	1800	980
40-H1101	Steam boiler No. 4	50	42	27286	793
P-SB#5	Steam boiler No. 5	50	54	27672	550
P-1B8	Wickes steam boiler	110	60	38357	340
P-H1302	Tank 101 heater	30	42	4604	750
P-H1303	Tank 101 heater	50	36	7330	750
P-HT120	Tank 120 heater	30	12	384	550
P-HT265	Tank 265 heater	34	10	384	550
P-HT601	Tank 601 heater	39	12	269	550
P-HT1321	Tank 1321 heater	44	12	269	550
P-HT1323	Tank 1323 heater	32	12	269	550
P-HT1324	Tank 1324 heater (2 stacks)	44	10	1922	550
P-1H4	FCCU feed preheater	141	72	35612	430
P-H350	CCR charge heater	152	78	47014	500
P-PH5	Unifiner charge heater	50	49	8387	700
P-H601	ROSE heater	100	39	10498	680
P-H960	Glycol dryer	30	12	426	400
P-H1301	Tank 107 heater	50	20	1298	750
P-HT134	Tank 134 heater (2 stacks)	48	13	3139	550
P-HT136	Tank 136 heater (2 stacks)	48	13	3139	550
P-HT264	Tank 264 heater	43	12	374	550
P-FS1451	South flare	48	12	--	1800
P-FS1403	West Flare			--	1800

SIGNIFICANT DISCHARGE POINTS - CONTINUED

Point ID	Description	Height Feet	Diameter Inches	Flow Rate ACFM	Temp. ºF
P-VENT6	CCR Regenerator vent	159	4	94	880
P-PC1A	Recip engine, Platformer PC-1A	25	11	2310	550
P-PC1B	Recip engine, Platformer PC-1B	25	11	2310	550
P-PC1C	Recip engine, Platformer PC-1C	25	11	2310	550
P-HC1A	Recip engine, Hysomer HC-1A	25	10	1160	550
P-HC1B	Recip engine, Hysomer HC-1B	25	10	1160	550
P-1ME258	FCCU Regenerator	140	72	110,218	580
P-H1331	Asphalt Hot Oil Heater	9	24	2,800	440
H-201	Vacuum charge heater	100	66	23,025	500
DHH-801	Hydrotreater charge heater	100	54	10,857	500
DHH-802	Fractionator charge heater	100	62	17,164	500
H-353	CCR charge heater	100	56	10,466	500
JH-102	Fractionator charge heater	100	56	13,955	500
GHH-2601	Splitter reboiler	110	52	13,580	521
GHH-2602	GHDS Reactor heater	104	32	6,468	595
GHH-2603	GHDS Stabilizer Reboiler	101	32	5,877	550
52-H01	Benfree Unit Reboiler	103	60	47,000	540
REFORMER	Hydrogen Plant Reformer Heater	68.5	35	34,286	400

SECTION V. PSD REVIEW

A. Project Emission Increases

Since the project results in a significant emission increase for CO_2e, a review of the net emission increases is required for CO_2e.

B. Project Net Emission Increases

WRC has not shut down any sources in the last three years so a netting analysis has not been performed. The project results in a significant net emission increase for CO_2e.

C. BACT

Since the project results in a significant net emission increase for CO_2e, the project is subject to PSD for CO_2e which includes BACT, modeling, and monitoring, if applicable. There are currently no applicable modeling or monitoring requirements for CO_2e. A source shall apply BACT for each regulated NSR pollutant for which a significant net emissions increase occurs. BACT shall apply to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit. The affected EUs subject to BACT are the proposed reformer as a new unit; the flare, as an existing unit which will have an increase in throughput, is not subject to BACT.

For the purpose of this analysis, GHG is assumed to be composed primarily of CO_2, with much smaller quantities of CH_4 and N_2O. Under EPA's new guidelines for GHG BACT, the typical top-down analysis approach is to be followed. Since CO_2 is not typically feasible to control, the available control options focus on potential improved process efficiency, leading to improved fuel efficiency, rather than end-of-stack types of control systems.

The applicant proposed the following measures as BACT:

<u>Reformer</u>

- Maintenance and fouling control
- Steam/feed preheating
- Combustion air controls
- Process integration (energy efficient design)
- Reformer with PSA hydrogen purification
- Latest proven burner designs
- Emissions limit: 120,280 lb CO_2e per million cubic feet natural gas feed.

OAC 252:100-8-31 states that BACT "*means an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification which the Director, on a case-by-case basis, taking into account energy, environmental, and economic impacts or other costs, determines is achievable for such source or modification…."* A BACT analysis is required to assess the appropriate level of control for each new or physically modified emissions unit for each pollutant that exceeds the applicable PSD Significant Emissions Rate (SER).

The U.S. EPA has stated its preference for a "top-down" approach for determining BACT and that is the methodology used for this permit review. After determining whether any New Source Performance Standard (NSPS) is applicable, the first step in this approach is to determine, for the emission unit in question, the available control technologies, including the most stringent control technology, for a similar or identical source or source category. If the proposed BACT is equivalent to the most stringent emission limit, no further analysis is necessary.

If the most stringent emission limit is not selected, further analyses are required. Once the most stringent emission control technology has been identified, its technical feasibility must be determined; this leads to the reason for the term "available" in Best Available Control Technology. A technology that is available and is applicable to the source under review is considered technically feasible. A control technology is considered available if it has reached the licensing and commercial sales stage of development. In general, a control option is considered applicable if it has been, or is soon to be, developed on the same or similar source type. If the control technology is feasible, that control is considered to be BACT unless economic, energy, or environmental impacts preclude its use. This process defines the "best" term in Best Available Control Technology. If any of the control technologies are technically infeasible for the emission unit in question, that control technology is eliminated from consideration.

The remaining control technologies are then ranked by effectiveness and evaluated based on energy, environmental, and economic impacts beginning with the most stringent remaining technology. If it can be shown that this level of control should not be selected based on energy, environmental, or economic impacts, then the next most stringent level of control is evaluated. This process continues until the BACT level under consideration cannot be eliminated by any energy, environmental, or economic concerns.

The five basic steps of a top-down BACT review are summarized as follows:

Step 1. Identify Available Control Technologies
Step 2. Eliminate Technically Infeasible Options
Step 3. Rank Remaining Control Technologies by Control Effectiveness
Step 4. Evaluate Most Effective Controls Based on Energy, Environmental, and Economic impacts
Step 5. Select BACT and Document the Selection as BACT

Reformer

Step 1. Identify Available Control Technologies

Potentially-applicable control technologies include add-on controls, inherently lower-emitting processes, practices, and designs, and combinations of the two. Since CO_2 is created as an unavoidable product of the steam reforming reaction, identification of available controls will focus on lower-emitting processes, practices, and designs. Although many alternatives will be eliminated in following steps, Step 1 should include all potential and relevant options. The following references were consulted in identifying potential control measures:

- EPA RBLC Clearinghouse
- "Energy Efficiency Improvement and Cost Saving Opportunities for Petroleum Refineries: An ENERGY STAR Guide for Energy and Plant Managers" (Document Number LBNL-56183, February 2005)
- "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry" (US EPA, October 2010); and
- Other BACT determinations for similar processes and equipment.

The following potential GHG controls were identified:

- Carbon capture and sequestration (CCS)
- Combined heat and power cogenerations (CHP)
- Process integration ("PINCH")
- Combustion air and feed/steam preheat
- Hydrogen purification process evaluation
- Hydrogen production optimization
- Maintenance and fouling control
- Combustion air controls
- New burner designs
- Adiabatic pre-reformer
- Alternative fuels.

Carbon capture and sequestration (CCS) is a "tailpipe" control process in which CO_2 is injected into deep aquifers, depleted oil and gas reservoirs, unmineable coal seals, or existing oil fields (as an enhanced oil recovery process). The process may be conducted either by using an amine unit to separate out CO_2 from the remainder of flue gases, or the entire stream may be injected.

Combined heat and power cogeneration (CHP) uses hot exhaust gases for generation of steam for turning electrical generation equipment. The process relies on there being significant temperature and oxygen concentrations in the exhausts.

Process Integration (PINCH) refers to synergistic designs where heating and cooling are provided by various process streams within a unit. Combustion and reactant pre-heating may be accomplished by cooling product streams.

Combustion air and feed/steam preheat refers to the use of heat recovery system to preheat the feed/steam and combustion air temperature. This option may result in a decrease in fuel consumption, because less heat must be created by combustion.

Hydrogen purification process evaluation is selecting the most efficient method of purifying hydrogen for usage, minimizing waste along with minimizing the amounts of fuels and raw materials and emissions. The three main hydrogen purification processes are pressure swing absorption (PSA), membrane separation, and cryogenic separation.

Hydrogen production optimization refers to utilizing hydrogen generated in other steps such as catalytic reforming or platforming in preference to operating a reformer.

Maintenance and fouling control is used in heaters and heat exchangers to prevent or eliminate fouling which reduces the efficiency of heat exchange.

Combustion air controls minimize the amount of air introduced into process heaters. Any air which enters a heater absorbs heat and increases the amount of fuel which must be combusted.

Newer burner designs combust fuel more efficiently, resulting in less fuel being needed.

Adiabatic pre-reforming is related to process integration in which a nickel catalyst is used to commence reforming at 900°F using waste heat from the reformer convection section.

Alternate fuels change from traditional fossil fuels to biomass.

A search of EPA's RBLC showed the following BACT determinations for reformers, listing three for ammonia facilities and one for a petroleum refinery. RBLC did not state the control technologies accepted for any determination.

RBLC ID	Facility	State	Permit Issuance Date	BACT Limit
IA-0106	CF Industries Nitrogen	Iowa	7/12/13	Not stated
LA-0272	Dyno Nobel Ammonia Production Facility	Louisiana	3/27/13	Not stated
IA-0105	Iowa Fertilizer Company	Iowa	10/26/12	Not stated
LA-0263	Alliance Refinery	Louisiana	7/25/12	Not stated

Step 2. Eliminate Technically Infeasible Options

The list of potential control technologies identified in Step 1 are evaluated for technical feasibility. EPA considers technologies to be technically feasible if:

- They have been demonstrated and operated successfully at a similar source, and
- They are available and applicable to the source under review.

Technologies in the pilot or R&D phases are not considered to be "available."

CCS: One end-of-stack control option to be considered is geologic sequestration of GHG. However, sequestration is not yet commercially available and appropriate geologic formations have not been proven for long-term underground storage in the vicinity of Wynnewood, OK. In addition, collateral environmental impacts that could result from sequestration have not been evaluated and require further study. Therefore, geologic sequestration is not considered to be a technically feasible control option at this time and is therefore eliminated from further consideration in this analysis. In addition, since sequestration is not yet commercially available, it is not possible to accurately estimate control costs.

Alternative Fuels: Natural gas is the lowest GHG emitting fuel and is a feedstock for the reformer process. Alternative fuels would have to be gasified prior to introduction into the process. They are, therefore, infeasible.

Adiabatic Pre-Reforming: There is only so much waste heat available from the process. The current designs are to use the waste heat in steam generation instead of different waste heat recovery processes.

Cogeneration: While technically feasible, this option pre-supposes that sufficient waste heat is available and there is sufficient oxygen in gases to support combustion. For this option to be used, other waste heat recovery options must be abandoned and excess air must be used.

Step 3 Rank Remaining Control Technologies by Control Effectiveness

The following table shows the remaining controls:

Control Technology Option	Estimated GHG Emission Reduction	Estimated Energy Efficiency Increase	Reference
Maintenance and Fouling Control	1-10% of process heater emissions	3-6%	October 2010 EPA GHG BACT Guidance & Energy Star Guide (LBNL-56183, February 2005)
Combustion Air and Feed/Steam Preheat	5% compared to typical reformer	5% compared to typical reformer	October 2010 EPA GHG BACT Guidance
Combustion Air Controls	1-3% of heater emissions	1-3%	October 2010 EPA GHG BACT Guidance
Process Integration (PINCH)	NA	NA	October 2010 EPA GHG BACT Guidance
Hydrogen Production Optimization	NA	NA	October 2010 EPA GHG BACT Guidance
Hydrogen Purification Process Evaluation	NA	NA	October 2010 EPA GHG BACT Guidance
New Burner Designs	NA	NA	Energy Star Guide (LBNL-56183, February 2005)

Step 4. Evaluate Most Effective Controls Based on Energy, Environmental, and Economic Impacts

Under the top-down approach, the highest ranking option is considered first and is evaluated on the basis of cost and collateral environmental impact. Since the highest ranking option is incorporated in the proposed reformer, along with several other options, costs have not been evaluated.

Step 5. Select BACT and Document the Selection as BACT

The following combination of energy efficiency techniques is selected as BACT:

- Maintenance and fouling control
- Steam/feed preheating
- Combustion air controls
- Process integration (energy efficient design)
- Reformer with PSA hydrogen purification
- Latest proven burner designs
- Emissions limit: 120,280 lb CO_2e per million cubic feet natural gas feed.

SECTION VI. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified in the application and listed in OAC 252:100-8, Appendix I, are listed below. Recordkeeping for activities indicated with "*" is listed in Specific Condition No. 7.

- * Stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or diesel fuel which are either used exclusively for emergency power generations or for peaking power service not exceeding 500 hours per year. The facility has emergency generators and an emergency stormwater pump. Upon the compliance date of changes to NESHAP Subpart ZZZZ (May 3, 2013), the stationary engines ceased to be Insignificant Activities.

- Space heaters, boilers, process heaters and emergency flares less than or equal to 5 MMBTUH heat input (commercial natural gas). Several of the non-NSPS heaters in EUG 40 and all of the heaters in EUG 90 are in this category.

- Emissions from stationary internal combustion engines rated less than 50 HP output. The facility included lawn maintenance equipment (movers, string trimmers, etc.) in this category.

- * Emissions from fuel storage/dispensing equipment operated solely for facility owned vehicles if fuel throughput is not more than 2,175 gallons/day, averaged over a 30-day period. The facility has a vehicle fueling operation, loading gasoline and diesel, at the facility maintenance shop.

- * Storage tanks with less than or equal to 10,000 gallons capacity that store volatile organic liquids with a true vapor pressure less than or equal to 1.0 psia at maximum storage temperature. The storage tanks in EUG No. 92 are in this category.

- * Emissions from storage tanks constructed with a capacity less than 39,894 gallons which store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature. This category overlaps with the above category, including the tanks in EUG 92.

- Additions or upgrades of instrumentation or control systems that result in emissions increases less than the pollutant quantities specified in OAC 252:100-8-3(e)(1). None listed but may be in the future.

- Alkaline/phosphate washers and associated burners. These are part of facility maintenance operations.

- Cold degreasing operations utilizing solvents that are denser than air. These are part of facility maintenance operations.

- Welding and soldering operations utilizing less than 100 pounds of solder and 53 tons per years of electrodes. These are conducted as part of facility maintenance, which is a "trivial activity," therefore no recordkeeping will be required.

- Torch cutting and welding of under 200,000 tons of steel fabricated. These are conducted as part of facility maintenance, which is a "trivial activity", therefore no recordkeeping will be required.

- Site restoration and/or bioremediation activities of <5 years expected duration. This category overlaps with the following category, and the facility includes a soil aeration pad.

- Hydrocarbon-contaminated soil aeration pads utilized for soils excavated at the facility only. The facility includes a soil aeration pad.

- * Non-commercial water washing operations and drum crushing operations (less than 2,250 barrels/year) of empty barrels less than or equal to 55 gallons with less than three percent by volume of residual material. A drum reclamation operation is present.

- Hazardous waste and hazardous materials drum staging areas. The facility includes a staging area for drummed hazardous wastes.

- Sanitary sewage collection and treatment facilities other than incinerators and Publicly Owned Treatment Works (POTW). Stacks or vents for sanitary sewer plumbing traps are also included (i.e., lift station)

- Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets, including hazardous waste satellite (accumulation) areas. The facility maintenance shop and laboratory have chemical storage areas.

- Hand wiping and spraying of solvents from containers with less than 1 liter capacity used for spot cleaning and/or degreasing in ozone attainment areas. This is conducted as part of facility maintenance.

- * Activities having the potential to emit no more than 5 TPY (actual) of any criteria pollutant. The vents in EUG 93 in the Hydrocracker Project permit application were identified as insignificant activities with potential emissions of less than 5 TPY of any criteria pollutant.

SECTION VII. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-5 (Registration, Emission Inventory, and Annual Operating Fees) [Applicable]
The owner or operator of any facility that is a source of air emissions shall submit a complete emission inventory annually on forms obtained from the Air Quality Division. An emission inventory was submitted and fees paid for previous years as required.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 5 includes the general administrative requirements for part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual emission units that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits:

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for single HAP that the EPA may establish by rule

Emission and operating limitations have been established from previous permits and applications for those emission units required to have limits.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]
Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for affirmative defense, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

OAC 252:100-13 (Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter) [Applicable]
This subchapter specifies limits for fuel-burning equipment particulate emissions based on heat input capacity. The following table compares limitations to calculated emissions. All units are in compliance with Subchapter 19.

COMPARISON OF PM EMISSIONS TO LIMITATIONS OF OAC 252:100-19

Unit	Heat Input Capacity, MMBTUH	PM Emission Limitation of OAC 252:100-19, lb/MMBTU	Anticipated PM Emission Rate, lb/MMBTU
P-CH1	96	0.35	0.0076
P-CH2	50.4	0.41	0.0076
P-CH3	35	0.46	0.0076
P-CH151	62.4	0.38	0.0084
P-CH121	39.6	0.43	0.0076
P-JH1	18.4	0.51	0.0076
P-JH2	18.4	0.51	0.0076
P-JH101	36.8	0.43	0.0076
P-KH1	66.5	0.38	0.0076
P-PH3	41.2	0.42	0.0076
P-HH1	15.8	0.57	0.0076
P-H152	12.5	0.58	0.0076

COMPARISON OF PM EMISSIONS TO LIMITATIONS OF OAC 252:100-19 - Continued

Unit	Heat Input Capacity, MMBTUH	PM Emission Limitation of OAC 252:100-19, lb/MMBTU	Anticipated PM Emission Rate, lb/MMBTU
P-5H1	84.1	0.35	0.0076
P-F1301	16.8	0.57	0.0076
40-H1101	88.6	0.35	0.0095
P-SB#5	72	0.36	0.0076
P-1B8	126	0.31	0.0076
P-H1302	10	0.60	0.0076
P-H1303	15.9	0.57	0.0076
P-HT120	1.0	0.60	0.0076
P-HT265	1.0	0.60	0.0076
P-HT601	0.7	0.60	0.0076
P-HT1321	0.7	0.60	0.0076
P-HT1323	0.7	0.60	0.0076
P-HT1324	5.0	0.60	0.0076
P-1H4	108.16	0.32	0.0076
P-H350	48.0	0.40	0.0076
P-H351	33.66	0.44	0.0076
P-H352	47.04	0.40	0.0076
P-PH5	19.0	0.51	0.0076
P-H601	24.2	0.48	0.0076
P-H960	1.34	0.60	0.0076
P-H1301	2.82	0.60	0.0076
P-HT134	8.4	0.60	0.0076
P-HT136	8.4	0.60	0.0076
P-HT264	1.0	0.60	0.0076
P-FS1451	0.1	0.60	0.0076
P-FS1402	0.1	0.60	0.0076
P-FS1401	0.1	0.60	0.0076
P-PC1A	4.4	0.60	0.0076
P-PC1B	4.4	0.60	0.0076
P-PC1C	4.4	0.60	0.0076
P-HC1A	2.5	0.60	0.0076
P-HC1B	2.5	0.60	0.0076
P-H1331	8.4	0.60	0.0076
P-H201	80	0.37	0.0076
P-DHH801	32.4	0.45	0.0076

COMPARISON OF PM EMISSIONS TO LIMITATIONS OF OAC 252:100-19 - Continued

Unit	Heat Input Capacity, MMBTUH	PM Emission Limitation of OAC 252:100-19, lb/MMBTU	Anticipated PM Emission Rate, lb/MMBTU
P-DHH802	36.3	0.45	0.0076
52-H01	65	0.39	0.0038
P-H353	30	0.46	0.0076
P-JH102	40	0.43	0.0076
P-GHH2601	39.6	0.43	0.0076
P-GHH2602	14.0	0.56	0.0076
P-GHH2603	14.0	0.56	0.0076
40-HPB1	67	0.38	0.0085
40-WPB1	96	0.34	0.0085
REFORMER	126	0.33	0.006

The flares do not meet the definition of “fuel-burning equipment,” therefore are not subject to these standards.

Subchapter 19 also limits PM emissions from various processes which are both process and fuel-burning equipment. Limitations are specified based on process weight rate. The process weight at the FCCU is the sum of the catalyst circulation rate (up to 800 TPH) plus the gas oil charge rate. Assuming a specific gravity of 1.05 and a feed rate up to 833 BPH, a gas oil feed rate of 153 TPH is calculated for a total process weight rate of 953 TPH. The following table shows the process weight rates, allowable PM emissions rates, and permit limitations. The anticipated PM emissions rate from the FCCU is in compliance with Subchapter 19.

COMPARISON OF PM EMISSION RATES TO ALLOWABLE EMISSION RATES UNDER OAC 252:100-19

Process Unit	Process Weight, TPH	OAC 252:100 -19 Allowable PM Emissions, lb/hr	PM Emissions, lb/hr
FCCU	953	77.0	15.4
Asphalt unit (P-F1301)	40	42.5	0.13

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. The FCCU is subject to an NSPS opacity limitation, therefore it is not subject to Subchapter 25.

OAC 252:100-29 (Fugitive Dust) [Applicable]
Subchapter 29 prohibits the handling, transportation, or disposition of any substance likely to become airborne or windborne without taking "reasonable precautions" to minimize emissions of fugitive dust. No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards. Most facility roads are paved, and FCCU catalyst handling equipment is enclosed. These measures achieve compliance with the "reasonable precautions" requirement.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 5 limits sulfur dioxide emissions from new equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/million BTU heat input. This is equivalent to approximately 0.2 weight percent sulfur in the fuel gas which is equivalent to 2,000 ppm sulfur. All fuel-burning equipment constructed after June 11, 1973, is also subject to NSPS Subpart J or Ja, which specify a more stringent limitation: 160 ppm sulfur, or about 0.0234 lb/MMBTU. The permit will require the use of commercial natural gas or sweetened refinery fuel gas with a maximum fuel sulfur content of 160 ppm for fuel-burning equipment constructed after July 1, 1972, to ensure compliance with Subchapter 31. One heater, P-1H4, is under a Consent Order to use only commercial-grade natural gas or sweetened refinery fuel gas with a maximum fuel sulfur content of 160 ppm sulfur.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
Subchapter 33 affects new fuel-burning equipment with a rated heat input of 50 MMBTUH or more. The following table compared anticipated NOx emission rates with applicable limitations of Subchapter 33. Most of the fuel-burning equipment was either constructed prior to October, 1971, or is smaller than the 50 MMBTUH de minimis level; the thermal oxidizer and flares are not defined as "fuel-burning equipment."

COMPLIANCE WITH NO_2 EMISSIONS LIMITATIONS

Unit	Description	NO_2 Emission Limitation of OAC 252:100-33, lb/MMBTU	Anticipated NO_2 Emission Rate, lb/MMBTU
P-1H4	Feed preheater	0.2	0.10
P-1B8	Wickes steam boiler	0.2	0.10
P-VH101	Vacuum charge heater	0.2	0.10
40-H1101	Indeck Steam Boiler	0.2	0.06
P-H48001	SRU Hot Oil Heater	0.2	0.15
P-CH151	Crude Charge Heater	0.2	0.06
40-HPB1	Holman Package Boiler	0.2	0.11
40-WPB1	Wabash Package Boiler	0.2	0.11
52-H01	Benfree Reboiler	0.2	0.035
REFORMER	Hydrogen Plant Reformer	0.2	0.06

OAC 252:100-35 (Carbon Monoxide) [Applicable]
Subchapter 35 affects the petroleum catalytic cracking unit (FCCU). Subchapter 35 requires “complete” secondary combustion, which is defined in the rule as removal of 93% or more of the CO generated. The catalyst regenerator provides essentially complete CO combustion, achieving compliance with Subchapter 35.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. Part 3 also requires storage tanks constructed after December 28, 1974, with a capacity of more than 40,000 gallons and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a either an external floating roof, a fixed roof with an internal floating cover, a vapor recovery system, or other equally effective control methods approved by the DEQ. Tanks subject to the floating roof standards of NSPS, Subparts K, Ka, or Kb are exempt from these requirements. All tanks constructed after December 28, 1974 are either subject to NSPS control requirements or contain organic liquids with vapor pressures below 1.5 psia.

Tanks storing diesel, jet fuel kerosene, asphalt, acid, caustic, or sour water are not subject because the products are not VOCs with a vapor pressure of 1.5 or greater under actual storage conditions. The gasoline and crude oil storage tanks with floating roofs are subject to the floating roof requirements of NSPS, therefore not subject to Subchapter 37.

<u>Part 3</u> applies to VOC loading facilities constructed after December 24, 1974. Facilities with a throughput greater than 40,000 gallons/day are required to be equipped with a vapor-collection and disposal system unless all loading is accomplished by bottom loading with the hatches of the tank truck or trailer closed. Loading facilities subject to NSPS Subpart XX or NESHAP Subpart R are exempt from these requirements.

The light products loading terminal at the refinery is equipped with a vapor-collection and disposal system. This terminal is also subject to NESHAP Subpart R and is exempt from these requirements.

<u>Part 5</u> limits the VOC content of coating operations. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment which is exempt.

<u>Part 7</u> requires all VOC gases from a vapor recovery blowdown system to be burned by a smokeless flare or equally effective control device unless it is inconsistent with the "Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline" or any State of Oklahoma regulatory agency.

<u>Part 7</u> requires fuel-burning and refuse-burning equipment to be operated and maintained so as to minimize emissions of VOCs. Temperature and available air must be sufficient to provide essentially complete combustion.

<u>Part 7</u> requires effluent water separators openings or floating roofs to be sealed or equipped with an organic vapor recovery system. The oil water separators process "slop oil" with a vapor pressure below 1.5 psia, the threshold of applicability of Subchapter 37.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
This subchapter regulates toxic air contaminants (TAC) that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained, unless a modification is approved by the Director. Since no AOC has been designated there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from

any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

The following Oklahoma Air Pollution Control Rules are not applicable to this facility:

OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Landfills	not in source category

SECTION VIII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
The project is subject to PSD review based on a significant net increase of GHG. PSD review was conducted in Section V.

NSPS, 40 CFR Part 60
[Subparts A, Dc, J, Ja, K, Ka, Kb, XX, GGG, GGGa, and QQQ Are Applicable]
Subpart A (General Provisions) specifies general control device requirements for control devices used to comply with applicable subparts. The North Flares and new West Flare (EUG 46) and Hydrocracker Flare (EUG 45) receive VOC emissions from process units which are subject to NSPS Subpart GGG or GGGa. Standards for flares used to comply with emissions limitations are stated in 40 CFR 60.18; "the standards are placed here for administrative convenience and only apply to facilities covered by subparts referring to this section." Subparts GGG and GGGa require compliance with 40 CFR 60.482-10, and 60.482-10 requires compliance with 60.18 for flares used to comply with the standards. 40 CFR 60.18(f)(5) states that the maximum steam-assisted flare exit velocity shall be determined by the following equation:

$$\mathrm{Log}_{10}\,(V_{max}) = (H_t + 28.8)/31.7$$

where H_t = the net heating value of the flared gas, MJ/SCM. The section further requires that the flare be monitored for the presence of a pilot flame and that the flare be operated with no visible emissions.

Subparts D and Da (Steam Generating Units) affect boilers with a rated heat input greater than 250 MMBTUH. The refinery does not have a boiler larger than 250 MMBTUH.

Subpart Db (Steam Generating Units) affects boilers with a rated heat input above 100 MMBTUH which commenced construction, reconstruction, or modification after June 19, 1984. Conversion of the Wickes Boiler (P-18B) from being a CO boiler to refinery fuel gas predated Subpart Db. The Indeck, Wabash, and Holman steam boilers are smaller than 100 MMBTUH, and the Wickes Boiler was installed prior to June 19, 1984. Waste heat recovery boilers in the new Reformer are not subject to Subpart Db since no fuel is combusted strictly for the purpose of creating steam.

Subpart Dc (Steam Generating Units) affects boilers with a rated heat input between 10 and 100 MMBTUH which commenced construction, reconstruction, or modification after June 9, 1989. Subpart Dc specifically excludes process heaters. The three boilers in EUG-36 were constructed after 1989, and are subject to Subpart Dc. Gas-fired boilers are required only to keep records of fuels used.

Subpart J (Petroleum Refineries) applies to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and Claus sulfur recovery plants. All fluid catalytic cracking unit catalyst regenerators which commence construction or modification after June 11, 1973, but before January 17, 1984, are subject to the following limitations:

- a PM emission limitation of 0.1 lb/1,000 lbs of coke burn-off, which is required to be continuously monitored and recorded;
- a CO emission limitation of 500 ppm by volume on a dry basis which is required to be continuously monitored and recorded; and

All fuel combustion devices which commence construction or modification after June 11, 1973, are subject to a fuel gas H_2S limitation of 0.10 grains/DSCF which is required to be continuously monitored and recorded. Fuel gas combusted by the affected units is monitored and recorded at one location. All emission limits, monitoring, and recordkeeping requirements will be incorporated into the permit. The replacement boilers are subject to these standards.

Subpart Ja, Petroleum Refineries. On June 24, 2008, EPA promulgated standards for new, modified, or reconstructed affected facilities at petroleum refineries. The provisions of this subpart apply to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices, including flares and process heaters, and sulfur recovery plants. Only those affected facilities that begin construction, modification, or reconstruction after May 14, 2007, are subject to this subpart.

Under 40 CFR Part 60.100a(c)(1), adding any new piping from a process unit to a flare is explicitly considered a modification, making the flare subject to Subpart Ja, the work practice standards of 40 CFR 60.103a, and performance testing requirements under 40 CFR Part 60.8. Between the modifications which have occurred and which are proposed, all flares will be treated as being subject to Subpart Ja.

Fuel gas combustion device means any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid. The new heaters in the GHDS Unit, the Benfree Unit reboiler, and the Hydrogen Plant Reformer are considered fuel gas combustion devices which commenced construction after May 14, 2007, and are subject to the final standards promulgated in this subpart.

Subpart Ja includes NOx standards for units which are larger than 40 MMBTUH capacity. All of the new heaters in the GHDS Unit are smaller than the 40 MMBTUH threshold, except for GHH-2601, which is subject to Subpart Ja. The Benfree Unit reboiler is subject to a limitation of 0.04 lb/MMBTU NOx. With manufacturer emissions guarantees of 0.035 lb/MMBTU, the reboiler will comply with Subpart Ja. The Hydrogen Plant Reformer heater is subject to a NOx limitation of 60 ppmv (dry basis, corrected to 0-percent excess air) or 0.060 lb/MMBTU.

Subpart K (Storage Vessels for Petroleum Liquids) affects storage vessels for petroleum liquids which have a storage capacity greater than 40,000 gallons but less than 65,000 gallons and which commenced construction, reconstruction, or modification after March 8, 1974, or which have a capacity greater than 65,000 gallons which commenced construction, reconstruction, or modification after June 11, 1973, and prior to May 19, 1978. “Petroleum liquids” does not include diesel, jet fuel, and kerosene. Storage vessels storing a petroleum liquid with a true vapor pressure of 1.5 psia to 11.1 psia are required to be equipped with a floating roof, a vapor recovery system, or their equivalent. If the true vapor pressure exceeds 11.1 psia, the storage vessel is required to be equipped with a vapor recovery system. All required recordkeeping and equipment standards will be incorporated into the permit. The tanks in EUGs 3, 10, and 14 are subject to Subpart K.

Subpart Ka (Storage Vessels for Petroleum Liquids) affects storage vessels for petroleum liquids which have a storage capacity greater than 40,000 gallons and which commenced construction, reconstruction, or modification after May 18, 1978, and prior to July 23, 1984. Storage vessels storing a petroleum liquid with a true vapor pressure of 1.5 psia to 11.1 psia are required to be equipped with an external floating roof, a fixed roof with an internal floating cover, a vapor recovery system, or their equivalent. The type of roof or control has to meet the specifications of this Subpart. All required recordkeeping and equipment standards will be incorporated into the permit. The vessels in EUGs 5 and 13 are subject to Subpart Ka.

Subpart Kb (VOL Storage Vessels) affects storage vessels for volatile organic liquids (VOLs) which have a storage capacity greater than or equal to 19,813 gallons and which commenced construction, reconstruction, or modification after July 23, 1984. Tanks with a capacity of less than 39,890 gallons and which store a VOL with a maximum true vapor pressure of less than 2.175 psia and tanks with a capacity equal to or greater than 39,890 gallons which store a VOL with a maximum true vapor pressure of less than 0.5 psia are no longer subject to Subpart Kb as of October 15, 2003. The vessels in EUGs 7 and 12 are subject to Subpart Kb. The replacement T-110 will not be subject to Subpart Kb since its vapor pressure is less than 0.5 psia.

Subpart XX (Bulk Gasoline Terminals) affects loading racks at bulk gasoline terminals which deliver liquid product into gasoline tank trucks and that commenced construction or modification after December 17, 1980. Subpart XX affects the total of all the loading racks at a bulk gasoline terminal. "Loading rack" is defined as "the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill delivery tanks trucks." The loading terminal was modified in 1986 by the addition of a loading rack. New vapor processing systems are limited to 35 mg of VOC per liter of gasoline loaded. The loading system and all tank trucks are required to be vapor-tight. Initial testing of valves, piping, meters, etc. is required to use Method 21 (10,000 ppm VOC leak threshold), but after initial testing, monthly inspection of potential leak components is acceptable. Subpart XX affects the product loading terminal, EUG-20.

Subpart GGG (Equipment Leaks of VOC in Petroleum Refineries) affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at a process unit which commenced construction or modification after January 4, 1983, and which is located at a petroleum refinery. Subpart GGG affects the CCR Platformer (EU-3734A), the Alkylation Unit (EU-3735A), the new Diesel Hydrodesulfurization Unit (EU-3736A), the Hydrocracker (EU-3725A) and New Amine Unit (EU-3740C).

Subpart GGGa, Equipment Leaks of VOC in Petroleum Refineries. This subpart affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at a process unit, which commenced construction or modification after November 7, 2006, and which is located at a petroleum refinery. This subpart defines "process unit" as "components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates: a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product." Subpart GGGa requires the leak detection, repair, and documentation procedures of NSPS, Subpart VVa. All affected equipment which commenced construction or modification after November 7, 2006, in VOC service is subject to this subpart. All applicable requirements have been incorporated into this permit for the GHDS Unit and the Benfree Unit. The feeds to and flows from the Hydrogen Plant Reformer will all be less than the 10% by weight threshold for Subpart GGGa.

The definition of "modification" excludes an expenditure for a physical or operational change which does not exceed the following allowance:

$$P = R * A$$

Where P is the asset repair allowance, R = facility replacement cost, and A is as defined:

$$A = Y * (B / 100)$$

Where B = 7.0 for petroleum refineries and Y is given by the following equation:

$$Y = 1.0 – 0.575 * \log (2006 – \text{year of construction})$$

(Note: the equation above is exactly how the subpart shows it. The subtraction will always give a negative number, and a logarithm of negative number cannot be taken; it seems likely that the two values were reversed.)

With a year of construction of 2013, Y = 0.514. Putting 0.514 into the "A" equation, A = 0.036. With a replacement cost of the 2006 components of $8,000,000, the project in question must exceed a cost of $288,000 to be considered a "modification." The cost of the new components has been estimated at $20,000, which is less than the cost threshold for "modification" as stated in Subpart GGGa.

<u>Subpart QQQ</u> (VOC Emission from Petroleum Refinery Wastewater Systems) applies to individual drain systems, oil-water separators, and aggregate facilities located in a petroleum refinery and which commenced construction, modification, or reconstruction after May 4, 1987. Drains are required to be equipped with water seal controls. Junction boxes are required to be equipped with a cover and may have an open vent pipe. Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces. Oil-water wastewater separators shall be equipped with a fixed roof which meets the required specifications. Subpart QQQ affects the equipment in EUGs 57, 59, 60, 61, and 64.

<u>Subpart JJJJ</u>, Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (SI-ICE). This subpart was published in the Federal Register on January 18, 2008. It promulgates emission standards for new SI engines ordered after June 12, 2006 and all SI engines modified or reconstructed after June 12, 2006, regardless of size. The specific emission standards (either in g/hp-hr or as a concentration limit) vary based on engine class, engine power rating, lean-burn or rich-burn, fuel type, duty (emergency or non-emergency), and manufacture date. Engine manufacturers are required to certify certain engines to meet the emission standards and may voluntarily certify other engines. An initial notification is only required for owners and operators of engines greater than 500 HP that are non-certified. Subpart JJJJ exempts lean-burn engines between 500-hp and 1,350-hp capacity which were manufactured prior to January 1, 2008. All engines were manufactured prior to the applicability dates.

NESHAP, 40 CFR Part 61 [Applicable]
Subpart J (Equipment Leaks (Fugitive Emissions Sources) of Benzene) affects process streams with are 10% by weight or more benzene. One process stream from the No. 2 Splitter is expected to contain 10-30% benzene. However, 40 CFR Part 63.640(p) states that any equipment subject to both Subpart J and Part 63, Subpart CC, is required only to comply with Subpart CC. The modified equipment is already subject to the MACT and will remain so.

Subpart FF (Benzene-contaminated Waste Operations) affects wastewater treatment systems at petroleum refineries where benzene content of wastewaters exceed 1.0 metric ton per year. Those refineries whose benzene content is between 1.0 and 10.0 metric tons per year are required only to analyze the wastewaters for the presence of benzene to demonstrate that the amount of benzene in wastewater at the refinery is less than 10.0 TPY. The Title V application included an analysis of wastewater streams showing a benzene content of 6.4 metric tons in 2007 (later values were not available at the time of application submittal). The new equipment in the Benfree Unit is not expected to increase benzene in wastewater above the 10 TPY threshold. The Hydrocracker Project does not include benzene-containing wastewater streams, so this does not affect the regulatory analysis.

NESHAP, 40 CFR Part 63 [Subparts CC, UUU, ZZZZ, DDDDD, and LLLLL Applicable]
Subpart CC (Petroleum Refineries) affects process vents (except FCCUs and catalyst regenerators) with HAP concentrations exceeding 20 ppm, storage vessels, wastewater streams and treatment, equipment leaks, gasoline loading racks, marine vessel loading system, and pipeline breakout stations. Of the affected equipment, storage tanks, equipment leaks, process vents, wastewater streams and treatment, and a gasoline loading rack are present at this refinery.

Storage tanks: existing storage tanks with HAP concentrations above 4% and which have vapor pressures above 1.5 psia are required to implement controls identical to NSPS Subpart Kb. The tanks in EUGs 9, 10, 11, 12, 13, and 14 are all subject to MACT requirements. Under the overlap provisions of Subpart CC, tanks which are subject to NSPS Subpart Kb shall comply with that subpart.

Process Vents: any refinery unit process vent with greater than 20 ppm HAPs and which emit more than 33 kg/day VOC are subject to control requirements. Subpart CC requires affected vents to be equipped with 98% efficient controls, vented to a flare, be vented to a combustion unit firebox, or reduced to 20 ppm HAP or less. All affected process vents have been vented to the refinery flare system or fuel gas system. The proposed deaertor vent, blowdown vent, and PSA hydrogen vent have HAP emissions below the 6.8 kg/day applicability threshold.

Equipment Leaks: these standards affect valves, flanges, pumps, and compressors except for compressors in hydrogen service. Process streams with 5% or more HAPs are required to comply. Subpart CC provides a phased schedule of compliance with standards. Phase III standards are in effect following February 18, 2001. Under the overlap provisions of Subpart CC, equipment which is subject to NSPS Subpart GGG shall comply with that subpart.

Gasoline Loading Terminal: Subpart CC states that the requirements of Subpart R are applicable but with the August 18, 1998, compliance deadline. Subpart R limits total VOC emissions to 10 mg per liter gasoline loaded, requires on meters, arms, and other components which may leak, and requires that tank trucks loaded be vapor-tight. The facility has a carbon adsorption unit and CEM on the discharge to comply with these standards.

Wastewater Streams and Treatment: Subpart CC requires refineries whose benzene content in wastewater is between 1 and 10 metric tons per year to monitor benzene content. (Subpart CC repeats standards for 40 CFR Part 61 Subpart FF for benzene-contaminated wastewater systems).

Subpart UUU (Petroleum Refineries Catalytic Cracking, Catalytic Reforming, and Sulfur Plant Units) was promulgated on April 11, 2002. The compliance date for this regulation was April 11, 2005. The SRU, CCR regenerator vent and FCCU catalyst regenerator are subject to these standards. The CCR and FCCU are required to achieve either 98% control of organic HAPs or 20-ppm corrected to 3% oxygen. The FCCU is subject to NSPS, Subpart J, therefore its limits apply (0.1 lb PM per 1,000 lbs coke burn-off). The SRU is limited to 250 ppm SO_2 corrected to 0% oxygen.

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart previously affected only RICE with a site rating greater than 500 brake horsepower that were located at a major source of HAP emissions. On January 18, 2008, the EPA published a final rule that promulgates standards for new and reconstructed engines (after June 12, 2006) with a site-rating less than or equal to 500 HP located at major sources, and new and reconstructed engines (after June 12, 2006) located at area sources. Owners and operators of new or reconstructed engines (after June 12, 2006) at area sources, and new or reconstructed engines with a site-rating equal to or less than 500 HP located at a major source (except new or reconstructed 4-stroke lean-burn engines with a site-rating greater than or equal to 250 HP and less than or equal to 500 HP located at a major source) must meet the requirements of Subpart ZZZZ by complying with either 40 CFR Part 60 Subpart IIII (for CI engines), or 40 CFR Part 60 Subpart JJJJ (for SI engines). Owners and operators of new or reconstructed 4SLB engines with a site-rating greater than or equal to 250 HP and less than or equal to 500 HP located at a major source are subject to the same MACT standards previously established for 4SLB engines above 500 HP at a major source, and must also meet the requirements of 40 CFR Part 60 Subpart JJJJ, except for the emission standards for CO.

Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters at major sources of HAPs. The “new” gas-fired units in the GHDS Unit, Benfree Unit, and Hydrogen Plant Reformer are subject to requirements for annual tune-ups or five year tune-ups (if equipped with a continuous oxygen trim system).

Subpart LLLLL (Asphalt Processing and Asphalt Roofing Manufacturing) affects asphalt blowstills and Group 1 storage vessels, which are defined as those vessels which are larger than 47,000 gallons and store asphalt at a temperature greater than 500°F or have a maximum true vapor pressure greater than 1.5 psia. Subpart LLLLL requires affected facilities to reduce total hydrocarbons by 95%, or to route emissions to a 99.5% efficient combustion device, or to route emissions to a combustion device which does not use auxiliary fuel and which achieves hydrocarbon destruction of 95.8%, or to route emissions to a process heater or boiler with a heat input capacity of 44 MW or greater, or to route emissions to a flare. The storage tanks in EUG 1 and 15 are regulated as "Group 2" storage vessels since their storage temperature is less than 500°F.

Compliance Assurance Monitoring, 40 CFR Part 64 [Applicable]
Compliance Assurance Monitoring, as published in the Federal Register on October 22, 1997, applies to any pollutant specific emission unit at a major source that is required to obtain a Title V permit, if it meets all the following criteria:

- It is subject to an emission limit or standard for an applicable regulated air pollutant.
- It uses a control device to achieve compliance with the applicable emission limit or standard.
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY.

Most units which utilize "active" control devices are also subject to MACTs: the FCCU, the SRU, and the asphalt blowstill. (Floating roofs on tanks are not "active" controls, and most tanks with floating roofs are also subject to MACT requirements.) The refinery fuel gas amine unit controls the sulfur content of refinery fuel gas, however, the fuel sulfur content is also required to be monitored under NSPS Subpart J and Ja. Fuel sulfur monitoring as conducted for Subparts J/Ja is acceptable as CAM for combustion units using refinery fuel gas.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Applicable]
Toxic and flammable substances subject to this regulation are present in the facility in quantities greater than the threshold quantities. A Risk Management Plan was re-submitted to EPA on November 27, 2006, and was determined to be complete. More information on this federal program is available on the web page: *www.epa.gov/ceppo*.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A and F are Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).

Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.

Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.

The Standard Conditions of the permit address the requirements specified at §82.156 for persons opening appliances for maintenance, service, repair, or disposal; §82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; §82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; §82.166 for recordkeeping; § 82.158 for leak repair requirements; and §82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

SECTION IX. COMPLIANCE

Inspections

On June 29, 2010, a full compliance evaluation was conducted at Wynnewood Refining Company's ("WRC") Wynnewood Refinery ("Wynnewood"). The evaluations were conducted by Ms. Rhonda Jeffries of the Department of Environmental Quality, Air Quality Division ("DEQ"). Wynnewood was represented by Ms. Sidney Cabbiness, Environmental Manager, during the evaluation. Various items of non-compliance were identified.

There are currently eleven Enforcement actions shown on TEAM as currently in progress. The current construction permit application should be independent of those actions.

Tier Classification and Public Review

This application has been determined to be a Tier II because it is a construction permit for a significant modification to a Title V source.

The applicant published the "Notice of Filing a Tier II Application" in the *Wynnewood Gazette* on July 25, 2013, a weekly newspaper of general circulation in Garvin County. The notice said that the application was available for public review at the Wynnewood Public Library, 108 N. Dean A. McGee Avenue, Wynnewood, OK, or at the AQD office. A draft of this permit was also made available for public review for a period of thirty days as stated in another newspaper announcement on November 28, 2013. The facility is located within 50 miles of the border with the state of Texas; that state will be notified of the draft permit. The application was approved for concurrent public and EPA review. No comments were received from the public, adjacent state, or EPA Region VI.

The applicant has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the property.

Information on all permit actions is available for review by the public in the Air Quality section of the DEQ Web page:*http://www.deq.state.ok.us/*

Fees Paid

Major source construction permit fee of $5,000.

SECTION X. SUMMARY

The applicant has demonstrated the ability to comply with the requirements of the several air pollution control rules and regulations. There are no active compliance or enforcement Air Quality issues that would affect the issuance of this permit. Issuance of the permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Wynnewood Refining Company, LLC **Permit No. 2007-026-C (M-5)(PSD)**
Wynnewood Refinery

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on January 8, 2007, with supplemental information received October 5, 2012, and March 12 and June 10, 2013. The Evaluation Memorandum dated January 6, 2014, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain limitations or permit requirements. Commencing construction or continuing operations under this permit constitutes acceptance of, and consent to the conditions contained herein:

1. Emissions limitations and operational requirements: [OAC 252:100-8-6(a)(1)]

<u>EUG 1 – Cone Roof Tanks, Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)</u> The following emissions units are "grandfathered" (constructed prior to any applicable rule) and are limited to the existing equipment as it is.

EU	Point	Normal Contents	Capacity	Installed Date
P-T108	P-T108	Jet kerosene	13,800 bbl.	1945
P-T111	P-T111	Jet kerosene	5,000 bbl.	1945
P-T162	P-T162	JP-8 additive	1,000 bbl.	1954
P-T252	P-T252	Slurry oil	26,800 bbl.	1945
P-T253	P-T253	High-sulfur diesel	25,000 bbl.	1957
P-T256	P-T256	Jet kerosene	5,000 bbl.	1957
P-T260	P-T260	Slurry oil	5,100 bbl.	1957
P-T262	P-T262	Gas oil	5,100 bbl.	1959
P-T263	P-T263	Slop oil	5,100 bbl.	1959
P-T1441	P-T1441	Jet kerosene	34,800 bbl.	6/72
P-T1472	P-T1472	Low-sulfur diesel	34,700 bbl.	6/73
P-T2052	P-T2052	Slop oil	1,000 bbl.	1945
P-T101	P-T101	Asphalt	64,000 bbl.	1945
P-T107	P-T107	Asphalt	78,000 bbl.	1945
P-T120	P-T120	Asphalt	2,800 bbl.	1945
P-T134	P-T134	Asphalt	80,000 bbl.	1954
P-T136	P-T136	Asphalt	80,000 bbl.	1957
P-T265	P-T265	Asphalt	5,100 bbl.	1959
P-T269	P-T269	Asphalt	5,100 bbl.	1961

A. The above emissions units are limited to process changes which will not cause the tank to become defined as a "Group 1 storage vessel". [40 CFR 63.640(l)(2)(ii)]

EUG 3 – Cone Roof Tanks, Constructed 6/12/73 to 5/18/78 (NSPS Subpart K), Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	Maximum True Vapor Pressure, psia	Maximum Annual Throughput, bbl. (12-Month Rolling Total)	VOC	
					lb/hr	TPY
P-T126	P-T126	FCCU charge	0.3	3,650,000	39.83	87.22
P-T202	P-T202	FCCU charge	0.4	3,650,000	41.74	91.41
P-T1901	P-T1901	Heavy hydrocarbons	1.5	2,000	0.13	0.29
P-T1323	P-T1323	Asphalt	1.5	120,000	11.26	24.66
P-T1324	P-T1324	Asphalt	0.4	2,758,000	---	0.87

A. The permittee shall comply with all applicable operational monitoring requirements: keeping records of the dimensions and capacities of the tanks, the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of the liquid during the storage period.
[40 CFR 60.113(a)]

B. The permittee shall keep monthly records of throughput of each of the above tanks.
[OAC 252:100-43]

EUG 5 – Cone Roof Tanks, Constructed 5/18/78 to 7/22/84 (NSPS Subpart Ka), Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	Maximum True Vapor Pressure, psia	Maximum Annual Throughput, bbl. (12-Month Rolling Total)	VOC	
					lb/hr	TPY
P-T264	P-T264	Gas oil	0.5	321,000	8.34	18.28
P-T601	P-T601	Asphalt resin	0.5	525,000	8.07	17.68
P-T1321	P-T1321	Asphalt	1.5	120,000	11.02	24.14

A. The permittee shall comply with all applicable operational monitoring requirements: keeping records of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of the liquid during the storage period. [40 CFR 60.115a(a)]

B. The permittee shall keep monthly records of throughput of each of the above tanks.
[OAC 252:100-43]

EUG 7 – Cone Roof Tanks, Constructed after 7/23/84 (NSPS Subpart Kb), Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	Maximum True Vapor Pressure, psia	Maximum Annual Throughput, bbl. (12-Month Rolling Total)	VOC	
					lb/hr	TPY
P-T266	P-T266	Latex	1.5	36,500	0.71	1.55
P-T1474	P-T1474	Diesel additive	2.0	11,900	0.73	1.61
P-T1475	P-T1475	High-sulfur diesel	0.5	2,500,000	--	0.74
P-T200	P-T200	Diesel	0.5	6,195,000	--	1.90

A. The permittee shall comply with all applicable operational monitoring requirements:
1. keeping records of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of the liquid during the storage period. [40 CFR 60.116b(b)]
2. keeping records of the dimensions and capacity of the vessels. [40 CFR 60.116b(c)]

B. The permittee shall keep monthly records of throughput of each of the above tanks. [OAC 252:100-43]

EUG 9 – Internal Floating Roof Tanks Constructed Prior to 6/12/73, Subject to 40 CFR Part 63 Subpart CC (Group 1 Storage Vessels)

The following emissions units are “grandfathered” and are limited to the existing equipment as it is.

EU	Point	Normal Contents	Capacity	Installed Date
P-T146	P-T146	Premium unleaded gasoline	80,000 bbl.	1952
P-T501	P-T501	Jet fuel	25,700 bbl.	1969
P-T1471	P-T1471	Premium unleaded gasoline	34,800 bbl.	6/73
P-T257	P-T257	Unifined naphtha	10,000 bbl.	1957

A. Each of the above storage tanks shall be equipped with an internal floating roof. [40 CFR 63.119(a)(1)]
B. Each tank shall meet the internal floating roof requirements listed in 40 CFR 63.119(b)
C. The permittee shall comply with the compliance provisions found in 40 CFR 63.120(a).
D. The permittee shall follow the reporting requirements found in 40 CFR 63.122(a) and (d).
E. The permittee shall maintain records as required in 40 CFR 63.123(a).

EUG 10 - Internal Floating Roof Tanks, Subject to NSPS Subpart K, Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	Maximum True Vapor Pressure, psia	Maximum Annual Throughput, bbl. (12-Month Rolling Total)	VOC	
					lb/hr	TPY
P-T1473	P-T1473	Mineral spirits \ light reformate	11.0	738,100	3.44	7.54
P-T67	P-T67	Crude oil	11.0	9,855,000	3.83	8.38
P-T68	P-T68	Crude oil	11.0	9,855,000	3.83	8.38
P-T69	P-T69	Crude oil	11.0	9,855,000	3.83	8.38

A. The vessels shall be equipped with floating roofs [40 CFR 60.112(a)]

B. The permittee shall comply with all applicable operational monitoring requirements: keep records of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of the liquid during the storage period. [40 CFR 60.113(a)]

C. The permittee shall keep monthly records of throughput of each of the above tanks. [OAC 252:100-43]

EUG 11 – External Floating Roof Tanks, Constructed Prior to 6/12/73, Subject to 40 CFR Part 63 Subpart CC (Group 1 Storage Vessels)

EU	Point	Normal Contents	Capacity	Installed Date
P-T142	P-T142	Unleaded gasoline	55,000 bbl.	1954
P-T143	P-T143	Unleaded gasoline	55,000 bbl.	1957
P-T144	P-T144	Premium unleaded gasoline	55,000 bbl.	1954
P-T147	P-T147	FCCU gasoline	80,000 bbl.	1952
P-T150	P-T150	Platformate	24,800 bbl.	1952
P-T152	P-T152	Platformate	24,800 bbl.	1952
P-T154	P-T154	Heavy unicrackate	24,800 bbl.	1952
P-T164	P-T164	Light unicrackate \ light reformate	10,000 bbl.	1951
P-T168	P-T168	Alkylate	35,700 bbl.	1959
P-T250	P-T250	Jet fuel	10,000 bbl.	1958
P-T251	P-T251	Mineral spirits	10,000 bbl.	1957
P-T254	P-T254	Unleaded gasoline	24,800 bbl.	1958
P-T255	P-T255	Isomerate	24,800 bbl.	1954
P-T1470	P-T1470	Unleaded gasoline	79,600 bbl.	1972

A. Each of the above storage tanks shall be equipped with an external floating roof. [40 CFR 63.119(a)(1)]
B. Each tank shall comply with the external floating roof requirements listed in 40 CFR 63.119(c)
C. The permittee shall comply with the compliance provisions found in 40 CFR 63.120(b).
D. The permittee shall follow the reporting requirements found in 40 CFR 63.122(a) and (c).
E. The permittee shall maintain records as required in 40 CFR 63.123(a).

EUG 12 – External Floating Roof Tanks, Subject to NSPS Subpart Kb, Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	Throughput, Barrels per 12-Month Period	Vapor Pressure Limit Psia	VOC	
					lb/hr	TPY
P-T155	P-T155	Naphtha	511,000	11.0	--	1.66
P-T70	P-T70	Crude Oil	10,950,000	11.0	--	5.31
P-T148	P-T148	Gasoline	8,614,000	11.0	--	16.33
P-T140	P-T140	Naphtha	10,950,000	11.0	--	10.56
P-T138	P-T138	Naphtha	7,300,000	11.0	--	10.42
P-T203	P-T203	Gasoline / Diesel	5,739,625	11.0	--	3.82

A. The external floating roofs shall be equipped with a primary liquid-mounted or mechanical shoe seal and a secondary seal. [40 CFR 60.112b(a)(2)]
B. Each tank with an external floating roof shall not exceed a seal gap to area ratio of 10 square inches per foot diameter for the primary seal nor 1.0 square inch per foot of diameter for the secondary seal. Seal gap area shall be tested at least every 5 years. [40 CFR 60.113b(b)(4)(i)]
C. The permittee shall keep monthly records of throughput of each of the above tanks. [OAC 252:100-43]

EUG 13 – External Floating Roof Tank, Subject to NSPS Subpart Ka, Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Contents	Maximum True Vapor Pressure, psia	Maximum Annual Throughput, bbl. (12-Month Rolling Total)	VOC	
					lb/hr	TPY
P-T303	P-T303	Crude oil	9.0	17,739,000	7.20	31.55

A. The external floating roof shall be equipped with a primary liquid-mounted or mechanical shoe seal and a secondary seal. [40 CFR 60.112a(a)(1)]
B. Each tank with an external floating roof shall not exceed a seal gap to area ratio of 10 square inches per foot diameter for the primary seal nor 1.0 square inch per foot of diameter for the secondary seal. Seal gap area shall be tested at least every 5 years. [40 CFR 60.113a(a)]
C. The permittee shall keep monthly records of throughput of each of the above tanks. [OAC 252:100-43]

EUG 14 – External Floating Roof Tank, Subject to NSPS Subpart K, Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Contents	Maximum True Vapor Pressure, psia	Maximum Annual Throughput, bbl. (12-Month Rolling Total)	VOC	
					lb/hr	TPY
P-T1449	P-T1449	Crude oil	11.0	19,710,000	13.75	30.11

A. Each external floating roof shall be equipped with a primary liquid-mounted or mechanical shoe seal and a secondary seal. [40 CFR 60.112(a)(1)]
B. The permittee shall comply with all applicable operational monitoring requirements: keep records of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of the liquid during the storage period. [40 CFR 60.113(a)].
C. The permittee shall keep monthly records of throughput of each of the above tanks. [OAC 252:100-43]

EUG 15 - Asphalt Unit Tanks Subject 40 CFR Part 63 Subpart CC

Tank ID	Type	Material Handled	Capacity (bbls)	Height (ft)	Diameter (ft)	VOC Emissions Limits, TPY
P-T1331	Cone roof	Asphalt	5,000	40	30	0.444
P-T1332	Cone roof	Asphalt	5,000	40	30	0.444
P-T1333	Cone roof	Asphalt	5,000	40	30	0.444
P-T1337	Cone roof	Asphalt	1,500	32	18.5	0.301
P-T1338	Cone roof	Asphalt	1,500	32	18.5	0.301
P-MP1330	Cone roof	Asphalt	9	8	3	0.346
P-T1330	Cone roof	Asphalt	90	8	10	0.080

A. The permittee shall be authorized to process and modify up to a total throughput of 1,090,300 barrels per year of asphalt, 12-month rolling total. [OAC 252:100-8-6]
B. No discharge of greater than 20% opacity shall be allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. [OAC 252:100-25]

C. H_2S discharges from storage tanks and processing vessels shall be limited to 200 ppm or less. All air discharges from storage tanks and process vessels shall be vented to Sulfatreat or equivalent devices for control of H_2S emissions. Testing of H_2S emissions from these points shall be conducted at least once per week using Draeger tubes or an equivalent method approved by AQD. Testing shall be conducted in a manner to preclude dilution of the sample with ambient air. [OAC 252:100-31]

EUG 16 – External Floating Roof Tank, Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)

EU	Point	Normal Contents	Capacity	Installed Date
P-T110	P-T110	Hydrocracker feed	15,000 bbl.	2013

<u>EUG 17 – Cone Roof Tank (Sour Water With Diesel Blanket), Subject to NSPS Subpart Kb, Subject to 40 CFR Part 63 Subpart CC (Group 2 Storage Vessels)</u>

EU	Point	Normal Contents	Throughput, Gallons per 12-Month Period	Vapor Pressure Limit Psia	VOC	
					lb/hr	TPY
P-T2051	P-T2051	Diesel / Sour Water	56,560,000	0.5	0.11	0.46

A. The permittee shall keep monthly records of throughput of the above tank. [OAC 252:100-43]

<u>EUG 20 – Product Loading Facility with Vapor Controls, Subject to 40 CFR Part 63 Subpart CC</u>

EU	Point	Description	Maximum Annual Throughput, bbl. (12-Month Rolling Total)	VOC		
				Milligrams per liter of gasoline loaded out	lb/hr	TPY
P-PLF1	P-PLF1	Product Loading Facility / Vapor Recovery Unit	7,227,000	10.0	3.08	12.67

A. The permittee shall comply with the loading rack standards of 40 CFR 63 Subpart CC. [40 CFR 63.422(a)]

B. Stack emissions from loading displacements shall not exceed 10 milligrams TOC per liter of gasoline loaded on a six-hour rolling average. [40 CFR 63.422(b)]

1. If using a Vapor Recovery Unit, a continuous emissions monitoring system shall be maintained measuring organic compound concentrations in the discharge from the loading rack. [40 CFR 63.427(a)(1)]

2. If using a Vapor Recovery Unit, Records of CEM readings on the vapor recovery unit stack shall be kept, showing calculated emission rates. [40 CFR 63.428(c)]
3. If using a flare, comply with the applicable requirements in 40 CFR 63.11.

C. The facility shall assure that nonvapor-tight gasoline cargo tanks will not be reloaded at the facility until vapor tightness documentation is obtained. [40 CFR 63.422(c)]
D. Records shall be kept of the annual gasoline cargo tank vapor-tightness certification of each tank truck loaded. 40 CFR 63.428(b)]
E. Semi-annual reports of loading of cargo tanks for which vapor tightness documentation had not been obtained, CEM readings and emissions calculations, and equipment leaks not repaired within 5 days shall be submitted. [40 CFR 63.428(g)]
F. Excess emission reports shall be submitted in accordance with 40 CFR 63.10(e)(3). [40 CFR 63.428(h)]
J. The permittee shall keep monthly records of throughput of gasoline. [OAC 252:100-43]

<u>EUG 29 - Fugitive Emissions Subject to 40 CFR Part 63 Subpart CC and/or NSPS Subpart GGGa</u> Fugitive VOC emissions do not have a specific limitation except to comply with the applicable leak detection and repair (LDAR) program.

<u>A. Fugitive Emissions Subject to NSPS Subpart GGGa:</u>

EU	Description	Equipment	Estimated Number of Items
EU-3726A	VOC Leakage at GHDS Unit	Gas/vapor valves	1000
		Light liquid valves	1000
		Flanges	4100
		Light liquid pumps	15
		Sampling connection	10
EU-3752A	VOC Leakage at Benfree Unit	Gas/vapor valves	500
		Light liquid valves	600
		Flanges	550
		Light liquid pumps	10
		Relief valves	5

A. The above process units are subject to NSPS Subpart GGGa and shall comply with all applicable requirements for leak detection and repair. [40 CFR 60.592(a)]
B. The owner operator shall comply with the requirements of §§ 60.482-1a through § 60.482-11a except as provided in § 60.593a:
   1. The operator shall demonstrate compliance with §§ 60.482-1a to 60.482-10a for all affected equipment within 180 days of initial startup which shall be determined by review of records, reports, performance test results, and inspection using methods and procedures specified in § 60.485a unless the equipment is in vacuum service and is identified as required by § 60.486a(e)(5). [§ 60.482-1a(a), (b), & (d)]
   2. The owner or operator shall comply with the monitoring, inspection, and repair requirements, for pumps in light liquid service, of §§ 60.482-2a(a), (b), and (c) except as provided in §§ 60.482-2a(d), (e), and (f).

3. Compressors in hydrogen service are exempt from the requirements of § 60.592a if an owner or operator demonstrates that a compressor is in hydrogen service. [§ 60.593a(b)(1)]
4. The owner or operator shall comply with the operation and monitoring requirements, for pressure relief devices in gas/vapor service, of §§ 60.482-4a(a) and (b) except as provided in § 60.482-4a(c) and (d).
5. The owner or operator shall comply with the applicable standards of § 60.482-5a for sampling connection systems.
6. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall be closed at all other times. [§ 60.482-6a]
7. The owner operator shall comply with the monitoring, inspection, and repair requirements, for valves in gas/vapor service and light liquid service, of §§ 60.482-7a(b) through (e), except as provided in 60.482-7a(f), (g), and (h), §§ 60.483-1a, 60.483-2a, and 60.482-1a(c). [§ 60.482-7a(a)]
8. The owner operator shall comply with the monitoring and repair requirements, or pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors, of §§ 60.482-8a(a) through (d). [§ 60.482-8a]
9. Delay of repair of equipment is allowed if it meets one of the requirements of §§60.482-9a(a) through (e).
10. The owner or operator using a closed vent system and control device to comply with these provisions shall comply with the design, operation, monitoring and other requirements of 60.482-10a(b) through (m). [§ 60.482-10a(a)]
11. The owner or operator shall comply with the applicable standards of § 60.482-11a for connectors in gas/vapor service and in light liquid service.
12. An owner or operator may elect to comply with the alternative requirements for valves of §§ 60.483-1a and 60.483-2a. [§ 60.592a(b) & § 60.482-1a(b)]
13. Each owner or operator subject to the provisions of NSPS Subpart GGGa shall comply with the test method and procedures of § 60.485a except as provided in §§ 60.593a. [§ 60.592a(d)]
14. Each owner or operator subject to the provisions of NSPS Subpart GGGa shall comply with the recordkeeping requirements of § 60.486a and the reporting requirements of § 60.487a. [§ 60.592a(e)]

EUG 30 - Fugitive Emissions Subject to 40 CFR Part 63 Subpart CC and/or NSPS Subpart GGG Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable leak detection and repair (LDAR) program.

A. Fugitive Emissions Subject to NSPS Subpart GGG:

EU	Description	Equipment	Estimated Number of Items
EU-3733A	VOC Leakage at No. 2 Crude Unit and No. 2 Vacuum Unit	gas valves	1500
		lt liq valves	1500
		hvy liq valves	100
		flanges	4000
		lt liq pumps	25
		hvy liq pumps	20
		gas relief valves	15
		compr. seals	1
EU-3734A	VOC Leakage at CCR Platformer, No. 1 Splitter, Hysomer, Naphtha Unifiner, and Hydrogen Plant	gas valves	2500
		lt liquid valves	2500
		hvy liq valves	100
		flanges	8750
		lt liq pumps	60
		hvy liq pumps	10
		compressor seals	1
		gas relief valves	15
EU-3735A	VOC Leakage at Alkylation Unit, Propylene Splitter, Butane Defluorinator	gas valves	1500
		lt liq valves	1500
		hvy liq valves	50
		flanges	4750
		lt liq pumps	15
		gas relief valves	30
EU-3736A	VOC Leakage at Diesel HDS Unit	gas valves	500
		lt liquid valves	1500
		hvy liq valves	50
		flanges	1300
		lt liq pumps	20
		hvy liq pumps	5
		gas relief valves	10
		compressors	2

A. The preceding process units are subject to NSPS Subpart GGG and shall comply with all applicable requirements for leak detection and repair. [40.CFR 60.592(a)]

B. The owner operator shall comply with the requirements of §§ 60.482-1 through § 60.482-10 except as provided in § 60.593:

1. The operator shall demonstrate compliance with §§ 60.482-1 to 60.482-10 for all affected equipment within 180 days of initial startup which shall be determined by review of records, reports, performance test results, and inspection using methods and procedures specified in § 60.485 unless the equipment is in vacuum service and is identified as required by § 60.486(e)(5). [§ 60.482-1(a), (b), & (d)]
2. The owner operator shall comply with the monitoring, inspection, and repair requirements, for pumps in light liquid service, of §§ 60.482-2(a), (b), and (c) except as provided in §§ 60.482-2(d), (e), and (f).
3. Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in § 60.482-1(c), § 60.482-3(h), and § 60.482-3(i). [§ 60.482-3(a)]
   i) Each compressor seal system shall comply with the requirements of §§ 60.482-3(b).
   ii) Each barrier fluid system shall be equipped with a sensor as required by § 60.482-3(d) that is monitored or equipped with an alarm as required by § 60.482-3(e) and repaired as required by §§ 60.482-3(f) and (g).
4. Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of § 60.14 or § 60.15 is exempt from §§ 60.482(a), (b), (c), (d), (e), and (h), provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of §§ 60.482-3(a) through (e) and (h).[§ 60.482-3(j)]

C. The owner operator shall comply with the operation and monitoring requirements, for pressure relief devices in gas/vapor service, of §§ 60.482-4(a) and (b) except as provided in § 60.482-4(c).

1. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall be closed at all other times. [§ 60.482-6]
2. The owner operator shall comply with the monitoring, inspection, and repair requirements, for valves in gas/vapor service and light liquid service, of §§ 60.482-7(b) through (e), except as provided in 60.482-7(f), (g), and (h), §§ 60.483-1, 60.483-2, and 60.482-1(c). [§ 60.482-7(a)]
3. The owner operator shall comply with the monitoring and repair requirements, or pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors, of §§ 60.482-8(a) through (d). [§ 60.482-8]

4. Delay of repair of equipment is allowed if it meets one of the requirements of §§60.482-9(a) through (e).
5. The owner or operators using a closed vent system and control device to comply with these provisions shall comply with the design, operation, monitoring and other requirements of 60.482-10(b) through (g). [§ 60.482-10(a)]
6. An owner or operator may elect to comply with the alternative requirements for valves of §§ 60.483-1 and 60.483-2. [§ 60.592(b) & § 60.482-1(b)]
7. Each owner or operator subject to the provisions of NSPS Subpart GGG shall comply with the test method and procedures of § 60.485 except as provided in §§ 60.593. [§ 60.592(d)]
8. Each owner or operator subject to the provisions of NSPS Subpart GGG shall comply with the recordkeeping requirements of § 60.486 and the reporting requirements of § 60.487. [§ 60.592(e)]

B. Fugitive Emissions Subject to MACT

EU	Description	Equipment	Estimated Number of Items
EU-3706A	VOC Leakage at Bulk Gasoline Terminal	lt liquid valves	10
		hvy liq valves	350
		flanges	1100
		lt liq pumps	25
		gas relief valves	15
EU-3722A	VOC Leakage at FCCU	gas valves	500
		lt liq valves	2000
		flanges	4000
		lt liq pumps	35
EU-3725A	VOC Leakage at Hydrocracker	gas valves	1510
		lt liq valves	1500
		hvy liq valves	100
		Flanges	5600
		lt liq pumps	40
		hvy liq pumps	5
		gas relief valves	20
		compressor seals	4
EU-3732A	VOC Leakage at No. 1 Crude Unit	gas valves	100
		lt liq valves	1600
		hvy liq valves	50
		flanges	5500
		lt liq pumps	30
		hvy liq pumps	15
		gas relief valves	15
		compressor	1

EU	Description	Equipment	Estimated Number of Items
EU-3740A	VOC Leakage at Steam, Utilities, and Flare System	gas valves	120
		lt liq valves	150
		hvy liq valves	20
		Flanges	250
		lt liq pumps	25
		hvy liq pumps	5
		gas relief valves	50
EU-3707	VOC Leakage at LPG Unit	gas valves	200
		lt liq valves	200
		hvy liq valves	5
		Flanges	4600
		lt liq pumps	15
		gas relief valves	15
EU-3727	VOC Leakage at RFG System	gas valves	1000
		lt liq valves	1000
		hvy liq valves	20
		Flanges	1500
		lt liq pumps	12
		gas relief valves	5
EU-3710	VOC Leakage at Tank Farm	lt liq valves	1150
		Flanges	4400
		lt liq pumps	40
EU-3711B	VOC Leakage at Asphalt Oxidizer	heavy liquid valves	600
		flanges	2600
EU-3732B	VOC Leakage at No. 1 Crude Unit	light liquid valves	250
		heavy liquid valves	800
		flanges	1200
		light liquid pumps	10
		heavy liquid pumps	35
EU-3734B	VOC Leakage at CCR Platformer Area	heavy liquid pumps	5

EU	Description	Equipment	Estimated Number of Items
EU-3735B	VOC Leakage at Aklylation Unit	open-ended valves	40
		heavy liquid pumps	10
		relief valves	35
		flanges	2000
EU-3711C	VOC Leakage at Asphalt Unit	hvy liq valves	200
		hvy liq pumps	25
		hvy liq flanges	600

A. The components identified in the above process units are subject to 40 CFR Part 63 Subpart CC and shall comply with all applicable requirements for leak detection and repair. Valves, flanges, other connectors, pumps, compressors, pressure relief devices, shall be monitored for leakage and repaired as specified. [40 CFR 63.648(a)]

B. The permittee shall comply with the Standards of Performance for Equipment Leaks of VOC from the Synthetic Organic Chemicals Manufacturing Industry NSPS Subpart VV, for each of the affected facilities located on-site. [40 CFR 60.480 to 60.489]

C. The owner operator shall comply with the requirements of §§ 60.482-1(a), (b), and (d) and § 60.482-2 through § 60.482-10 except as provided in § 60.593.

D. The owner or operator shall demonstrate compliance with §§ 60.482-1 to 60.482-10 for all affected equipment within 180 days of initial startup which shall be determined by review of records, reports, performance test results, and inspection using methods and procedures specified in § 60.485 unless the equipment is in vacuum service and is identified as required by § 60.486(e)(5). [§ 60.482-1(a), (b), & (d)]

E. The owner or operator shall comply with the monitoring, inspection, and repair requirements, for pumps in light liquid service, of §§ 60.482-2(a), (b), and (c) except as provided in §§ 60.482-2(d), (e), and (f).

F. Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in § 60.632(c), § 60.633(f), § 60.482-1(c), § 60.482-3(h), and § 60.482-3(i). [§ 60.482-3(a)]

G. Each compressor seal system shall comply with the requirements of §§ 60.482-3(b).
   i. Each barrier fluid system shall be equipped with a sensor as required by § 60.482-3(d) that is monitored or equipped with an alarm as required by § 60.482-3(e) and repaired as required by §§ 60.482-3(f) and (g).
   ii. Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of § 60.14 or § 60.15 is exempt from §§ 60.482(a), (b), (c), (d), (e), and (h) , provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of §§ 60.482-3(a) through (e) and (h).[§ 60.482-3(j)]

I. The owner operator shall comply with the operation and monitoring requirements, for pressure relief devices in gas/vapor service, of §§ 60.482-4(a) and (b) except as provided in § 60.482-4(c).

J. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall be closed at all other times. [§ 60.482-6]

K. The owner operator shall comply with the monitoring, inspection, and repair requirements, for valves in gas/vapor service and light liquid service, of §§ 60.482-7(b) through (e), except as provided in 60.482-7(f), (g), and (h), §§ 60.483-1, 60.483-2, and 60.482-1(c).[§ 60.482-7(a)]

   i) The owner operator shall comply with the monitoring and repair requirements, or pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors, of §§ 60.482-8(a) through (d). [§ 60.482-8]

   ii) Delay of repair of equipment is allowed if it meets one of the requirements of §§60.482-9(a) through (e).

   iii) The owner or operators using a closed vent system and control device to comply with these provisions shall comply with the design, operation, monitoring and other requirements of 60.482-10(b) through (g). [§ 60.482-10(a)]

L. An owner or operator may elect to comply with the alternative requirements for valves of §§ 60.483-1 and 60.483-2. [§ 60.482-1(b)]

EUG 35 - Fugitive Emissions Subject to Monitoring Requirements (40 CFR Part 63 Subpart CC and/or NSPS Subpart GGG). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	Description	Equipment	Estimated Number of Items
EU-3740C	VOC Leakage at New Amine Treating and Regeneration, SWS, SRU, & TGTU	gas valves	150
		lt liquid valves	100
		hvy liq valves	25
		flanges	1500
		lt liq pumps	10
		hvy liq pumps	15

A. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component. [40 CFR Part 63,Subpart CC]

   1. §63.642 General Standards – (a), (d)(1), (e), & (f);
   2. §63.648 Equipment Leak Standards – (a), (b), (c), & (e-i);
   3. §63.648 Reporting and Recordkeeping Standards – (d), & (f-h).

B. Equipment determined not to be in HAP service (contacting <5% by weight HAP) and which is in VOC service (contacting >10% by weight VOC) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
   1. §60.592 Standards (a-e);
   2. §60.593 Standards (a-e).

EUG 36 – Steam Boilers Subject to NSPS Part 60 Subpart Dc and Subpart J and MACT Part 63 Subpart DDDDD

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
40-H1101	Indeck steam boiler	0.83	3.61	2.33	10.19	5.43	23.78	0.60	2.62	9.12	39.95
40-HPB1	Holman package boiler	0.58	2.56	1.48	6.48	7.68	33.6	0.42	1.85	6.45	28.25
40-WPB1	Wabash package boiler	0.82	3.57	2.11	9.25	11.0	48.3	0.60	2.65	9.22	40.37

A. Fuel shall not contain more than 160 ppm sulfur (0.1 gr/DSCF). [40 CFR 60.104(a)(1)]
B. NOx emissions shall not exceed 0.2 lb/MMBTU. [OAC 252:100-33-2]
C. The sulfur content of fuel gas shall be continuously monitored for sulfur content.
[40 CFR 60.105(a)(3)]
C. Monthly records of fuels used in 40-H1101, 40-WPB1, and 40-HPB-1 shall be kept.
[40 CFR 60.48c(g)(2)]
E. The points in this emission unit group are subject to 40 CFR Part 63, Subpart DDDDD as finalized March 21, 2011, with a tentative compliance date of March 21, 2014.

EUG 37 - Fuel Gas Combustion Devices Subject to NSPS Part 60 Subpart Ja and MACT Part 63 Subpart DDDDD

Point ID	Emissions Unit	$PM_{2.5}$		SO_2		NO_x		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-GHH2601	GHDS Splitter Reboiler	0.35	1.55	1.60	2.53	2.85	12.49	0.26	1.12	3.91	17.14
P-GHH2602	GHDS Reactor Heater	0.13	0.55	0.56	0.89	1.01	4.42	0.09	0.40	1.38	6.06
P-GHH2603	GHDS Stabilizer Reboiler	0.13	0.55	0.56	0.89	1.01	4.42	0.09	0.40	1.38	6.06
REFORMER	Hydrogen Plant Reformer	0.76	3.01	0.13	0.53	7.44	29.63	0.32	1.26	3.78	15.03

A. The above units are subject to New Source Performance Standards (NSPS), Subpart Ja and shall comply with all applicable provisions. [40 CFR Part 60, Subpart Ja]
   1. § 60.102a Emission limitations;
   2. § 60.103a Work practice standards as applicable;
   3. § 60.104a Performance tests as applicable;
   4. § 60.107a Monitoring of operations – (a)(2), (3), and (4); and
   5. § 60.108a Recordkeeping and reporting requirements.

B. The above units shall only be fired with refinery fuel gas or pipeline-grade natural gas.
[OAC 252:100-8-6(a)(1)]
C. NOx emissions from the GHDS heaters (P-GHH2601, P-GHH2602, and P-GHH2603) shall not exceed 0.06 lb/MMBTU, expressed as NO_2.
[OAC 252:100-8-6(a)(1) and 40 CFR 60 Subpart Ja]
D. The points in this emission unit group are subject to 40 CFR Part 63, Subpart DDDDD as finalized March 21, 2011, with a tentative compliance date of March 21, 2014.

E. NOx emissions from the Hydrogen Plant Reformer shall not exceed 60 ppm (dry basis, corrected to 0% oxygen) determined daily on a 30-day rolling average.
[40 CFR 60.201a(g)(2)(ii)]

F. Total natural gas feed to the Hydrogen Plant Reformer (SMR) shall not exceed 1,752MMSCF per year, 12-month rolling total. [OAC 252:100-8-6(a)(1)]

G. CO_2e emissions from the Hydrogen Plant Reformer (SMR) shall not exceed 120,280 lb CO_2e / MMSCF natural gas feed, 30-day average. [OAC 252:100-8-34(b)]

H. Initial performance testing on the Reformer shall include Reference Methods 1 – 4, measurements of fuel heating value, and other data as necessary to show compliance with the CO_2e emissions limitation. [OAC252:100-43]

I. The design of the Reformer shall include the following elements: [OAC 252:100-8-6(a)(1)]
1. Maintenance and fouling control
2. Steam/feed preheating
3. Combustion air controls
4. Process integration (energy efficient design)
5. Reformer with PSA hydrogen purification
6. Latest proven burner designs

EUG 38 - Fuel Gas Combustion Devices, Subject to NSPS Subpart J and 40 CFR 63 Subpart DDDDD

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-VH101	Vacuum charge heater	0.49	2.15	2.21	9.68	3.96	17.34	0.36	1.56	5.44	23.81
P-DHH801	Hydrotreater charge heater	0.23	1.02	1.04	4.57	1.87	8.18	0.17	0.73	2.56	11.22
P-DHH802	Fractionator charge heater	0.37	1.61	1.65	7.22	2.95	12.93	0.26	1.16	4.5	17.75
P-H356	CCR charge heater	0.22	0.98	1.00	4.40	1.80	7.88	0.16	0.71	2.47	10.82
P-JH301	Fractionator charge heater	0.30	1.31	1.34	5.87	2.40	10.51	0.21	0.94	3.29	14.43
P-CH151	Crude charge heater	0.51	2.24	1.64	7.18	3.74	16.39	0.37	1.62	5.65	24.75

A. The above units are subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
7. § 60.104 Standards for SO_2 – (a)(1);
8. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii);
9. § 60.106 Test methods and procedures – (e).

B. The above units shall only be fired with refinery fuel gas or pipeline-grade natural gas.
[OAC 252:100-8-6(a)(1)]

C. The heaters in EUG-38 are subject to NESHAP, Subpart DDDDD and shall comply with all applicable provisions as and when the regulation is re-promulgated by EPA.

D. NOx emissions from each above heater shall not exceed 0.06 lb/MMBTU, expressed as NO_2.
[OAC 252:100-8-6(a)(1)]

E. The points in this emission unit group are subject to 40 CFR Part 63, Subpart DDDDD as finalized March 21, 2011, with a tentative compliance date of March 21, 2014.

EUG 39 - Fuel Gas Combustion Device, Subject to 40 CFR 63 Subpart LLLLL

EU	Point	Equipment	MMBTUH	Opacity Limit	PM Emission Limitation of OAC 252:100-19, lb/MMBTU	SO_2 Emission Limitation lb/hr
P-F1301	P-F1301	Asphalt oxidizer incinerator	16.8	20%	0.57	15.37

A. The Asphalt Unit thermal oxidizer (P-FS1301) shall be operated at a temperature of 1,198°F or greater except during start-up; during start-up, it may be operated at a temperature as low as 900°F. The operating temperature of the unit shall be continuously recorded. [OAC 252:100-43]

B. If future performance testing using the methods of 40 CFR Part 63, Subpart LLLLL, show that the unit achieves compliance with emissions limitations of Subpart LLLLL at a lower temperature, that lower operating temperature may be maintained.

EUG 40 - Grandfathered Fuel Gas Combustion Devices, Subject to MACT Part 63 Subpart DDDDD

The following emission units are "grandfathered" (constructed prior to any applicable rule). They are limited to the existing equipment as it is.

EU	Point	Equipment	MMBTUH	Opacity Limit	PM Emission Limitation of OAC 252:100-19, lb/MMBTU	SO_2 Emission Limits, lb/hr
P-CH1	P-CH1	Crude Fractionation heater	96	20%	0.35	9.10
P-CH2	P-CH2	Crude charge heater	50.4	20%	0.41	4.78
P-CH3	P-CH3	Crude preflash reboiler	35	20%	0.46	3.32
P-CH121	P-CH121	Vacuum charge heater	39.6	20%	0.43	3.76
P-JH1	P-JH1	Hydrocracker reactor heater	18.4	20%	0.51	1.75
P-JH2	P-JH2	Hydrocracker reactor heater	18.4	20%	0.51	1.75
P-JH101	P-JH101	Hydrocracker fractionator reboiler	36.8	20%	0.43	3.49
P-KH1	P-KH1	Hydrogen reforming heater	66.5	20%	0.38	6.31
P-PH3	P-PH3	Unifiner stripper reboiler	41.2	20%	0.42	3.90
P-HH1	P-HH1	Hysomer heater	16.8	20%	0.57	1.50
P-H152	P-H152	No. 2 splitter reboiler	12.5	20%	0.58	1.18
P-5H1	P-5H1	Alky depropanizer reboiler	84.1	20%	0.35	113.02
P-H1302	P-H1302	Tank 101 heater	10	20%	0.60	0.95
P-H1303	P-H1303	Tank 101 heater	15.9	20%	0.57	1.51
P-HT120	P-HT120	Tank 120 heater	1	20%	0.60	0.09

EU	Point	Equipment	MMBTUH	Opacity Limit	PM Emission Limitation of OAC 252:100-19, lb/MMBTU	SO_2 Emission Limits, lb/hr
P-HT265	P-HT265	Tank 265 heater	1	20%	0.60	0.09
P-HT601	P-HT601	Tank 601 heater	0.7	20%	0.60	0.07
P-HT1321	P-HT1321	Tank 1321 heater	0.7	20%	0.60	0.07
P-HT1323	P-HT1323	Tank 1323 heater	0.7	20%	0.60	0.07
P-HT1324	P-HT1324	Tank 1324 heater	5	20%	0.60	0.47

A. Fuel for these units shall not contain more than 450 ppm sulfur. [OAC 252:100-8-6(a)]

B. The sulfur content of fuel gas to the units listed shall be continuously monitored for sulfur content using a Continuous Emissions Monitor which has been certified and quality-assured using the methods and procedures of 40 CFR Part 60, Appendices A and F. [OAC 252:100-43]

C. The points in this emission unit group are subject to 40 CFR Part 63, Subpart DDDDD as finalized March 21, 2011, with a tentative compliance date of March 21, 2014.

EUG 41 - Fuel Gas Combustion Devices Subject to Oklahoma Rules and MACT Part 63 Subpart DDDDD

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-1B8	Wickes steam boiler	0.96	3.78	10.76	47.13	25.20	99.34	0.69	2.72	10.58	41.71

A. NOx emissions shall not exceed 0.2 lb/MMBTU. [OAC 252:100-33]

B. Fuel usage in this unit shall not exceed 1,242 MMSCF per year, 12-month rolling total basis.

C. Fuel for these units shall not contain more than 450 ppm sulfur. [OAC 252:100-8-6(a)]

D. The sulfur content of fuel gas to the units listed shall be continuously monitored for sulfur content using a Continuous Emissions Monitor which has been certified and quality-assured using the methods and procedures of 40 CFR Part 60, Appendices A and F. [OAC 252:100-43]

E. The points in this emission unit group are subject to 40 CFR Part 63, Subpart DDDDD as finalized March 21, 2011, with a tentative compliance date of March 21, 2014.

EUG 42 – Fuel Gas Combustion Devices Subject to NSPS Part 60 Subpart J and MACT Part 63 Subpart DDDDD

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-H350	CCR charge heater	0.98	4.29	3.40	14.88	12.87	56.36	0.71	3.45	10.81	47.35
P-PH5	Unifiner charge heater	0.24	1.04	0.76	3.33	3.12	13.68	0.17	0.75	2.62	11.49
P-H601	ROSE heater	0.31	1.34	0.98	4.30	2.01	8.82	0.22	0.97	3.38	14.82
P-H1301	Tank 107 heater	0.02	0.09	0.07	0.33	0.28	1.24	0.02	0.07	0.24	1.04
P-1H4	FCCU Feed preheater	0.82	3.60	2.86	12.51	21.63	94.75	0.59	2.61	9.09	39.79
P-SB#4R	Nebraska Package	0.81	3.53	2.58	11.3	10.6	46.4	0.58	2.55	8.90	39.

A. Fuel for these units shall not contain more than 160 ppm sulfur (0.1 gr/DSCF). [40 CFR 60.104(a)(1)]

B. The sulfur content of fuel gas to the units listed shall be continuously monitored for sulfur content. [40 CFR 60.105(a)(3)]

C. NOx emissions from P-1H4 shall not exceed 0.2 lb/MMBTU. [OAC 252:100-33]

D. The points in this emission unit group are subject to 40 CFR Part 63, Subpart DDDDD as finalized March 21, 2011, with a tentative compliance date of March 21, 2014.

EUG 43 – Asphalt Unit Heater, Subject to MACT Part 63 Subpart DDDDD

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-H1331	Asphalt Unit hot oil heater	0.064	0.280	0.005	0.022	0.840	3.679	0.046	0.202	0.706	3.090

A. The hot oil heater shall be fueled only with pipeline-grade natural gas. [OAC 252:100-31]

B. The points in this emission unit group are subject to 40 CFR Part 63, Subpart DDDDD as finalized March 21, 2011, with a tentative compliance date of March 21, 2014.

EUG 44 - Fuel Gas Combustion Devices Subject to NSPS Part 60 Subpart J and MACT Part 63 Subpart DDDDD

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-H48001	SRU Hot Oil Heater	0.59	2.59	1.77	7.76	7.80	34.19	0.43	1.88	6.55	28.72
P-HT134	Tank 134 heater	0.06	0.28	0.28	1.23	0.84	3.68	0.05	0.20	0.71	3.09
P-HT136	Tank 136 heater	0.06	0.28	0.28	1.23	0.84	3.68	0.05	0.20	0.71	3.09
P-HT264	Tank 264 heater	0.01	0.03	0.03	0.15	0.10	0.44	0.05	0.20	0.71	3.09

A. The above heaters are subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]

1. § 60.104 Standards for SO_2 – (a)(1);
2. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii);
3. § 60.106 Test methods and procedures – (e).

B. The above units shall only be fired with refinery fuel gas or pipeline-grade natural gas. [OAC 252:100-8-6(a)(1)]

C. NOx emissions from P-H48001 shall not exceed 0.15 lb/MMBTU. [OAC 252:100-33]

D. The points in this emission unit group are subject to 40 CFR Part 63, Subpart DDDDD as finalized March 21, 2011, with a tentative compliance date of March 21, 2014.

EUG 45 – Flares, Subject to 40 CFR Part 60 Subpart Ja

EU	Point	Equipment	Installed Date	SO_2	
				lb/hr	TPY
P-FS1451	P-FS1451	South Flare	1957	30.26	132.54
P-FS1503	P-FS1503	Hydrocracker Flare	2006	0.01	0.01
P-FS1403	P-FS1403	West Flare	2013	30.26	132.54

A. The flares shall be monitored continuously for the presence of a pilot flame. [40 CFR 60.18(f)]

B. The flares shall comply with all applicable provisions of NSPS, Subpart Ja including but not limited to: [40 CFR Part 60, Subpart Ja]
1. § 60.102a Emissions limitations;
2. § 60.103a Design, Equipment, work practice, or operational standards;
3. § 60.104a Performance tests;
4. § 60.107a Monitoring of emissions and operations for process heaters and other fuel gas combustion devices; and
5. § 60.108a Recordkeeping and reporting requirements.

EUG 46 - Fuel Gas Combustion Devices, Subject to NSPS Subpart Ja and 40 CFR 63 Subpart DDDDD

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
52-H01	Benfree Unit reboiler	0.25	1.08	2.18	3.54	2.28	9.96	1.69	7.39	2.44	10.68

A. The Benfree Reboilers shall comply with all applicable provisions of NSPS, Subpart Ja including but not limited to: [40 CFR Part 60, Subpart Ja]
1. § 60.102a Emissions limitations;
2. § 60.103a Work practice standards;
3. § 60.104a Performance tests;
4. § 60.107a Monitoring of emissions and operations for process heaters and other fuel gas combustion devices; and
5. § 60.108a Recordkeeping and reporting requirements.

B. The above unit shall be fueled with refinery fuel gas or pipeline-grade natural gas only. [OAC 252:100-8-6(a)(1) and OAC 252:100-31]

C. NOx emissions from each above heater shall not exceed 0.04 lb/MMBTU, expressed as NO_2. [40 CFR 60, Subpart Ja]

D. Performance testing as required by 40 CFR Part 60.8 shall be conducted within 60 days of achieving maximum production rate, not to exceed 180 days from initial start-up. [40 CFR 60.8]

EUG 51 – Miscellaneous Vents Subject to 40 CFR Part 63 Subpart CC

There are no emission limits applied to these units under Title V but they are limited to the existing equipment as it is.

EU	Point	Equipment	Installed Date
P-VENT7	P-VENT7	Asphalt light ends recovery sump	1970

EUG 53 – Vents Subject to Permit Limitations and 40 CFR Part 63 Subpart UUU

Point	Process	VOC	
		lb/hr	TPY
P-VENT6	CCR regenerator vent	2.20	9.63

A. The CCR regenerator vent is subject to 40 CFR Part 63, Subpart UUU.
B. The temperature limit for the CCR vent is 312°F as established in the performance test conducted December 6, 2011. The temperature limit may be changed at any time upon completion and submittal of an updated performance test to ODEQ.

[40 CFR 63.1567(a)(2)]

EUG 54 – Molten Sulfur Pit

EU	Point	Normal Contents	H_2S	
			lb/hr	TPY
P-SP301	P-SP301	Sulfur	0.014	0.06

A. The H_2S content of discharges from this unit shall not exceed 4,000 ppm. [OAC 252:100-8-6(a)(1)]
B. At least once every calendar quarter, the permittee shall conduct testing of H_2S concentrations in discharges from this unit. Testing may be done using Draeger tubes or an equivalent method approved by Air Quality. [OAC 252:100-43]

EUG 56 – Grandfathered Wastewater System Subject to 40 CFR Part 63 Subpart CC

The following emissions units are "grandfathered" and are limited to the existing equipment as it is.

EU	Point	Equipment	Installed Date
P-WW1	P-WW1	Process wastewater systems and open sewers	various

EUG 57 – Wastewater Systems Subject to NSPS Subpart QQQ and 40 CFR Part 63 Subpart CC

Point	Process	VOC	
		lb/hr	TPY
EU-WW2	CCR drain	0.035	0.153
	D-208 drain	0.035	0.153
	S-1450 drain	0.035	0.153
	S-1451 drain	0.035	0.153

A. Oil-water separators S-1450 and S-1451 and slop oil tank D-208 shall be vented to the refinery flare system or an equivalent (98% or more) efficient VOC emissions control device, except as provided in 40 CFR 60.692-3(f). [40 CFR60.692-3(b)]

EUG 58 – Open API Separator

The following emissions are "grandfathered" and are limited to the existing equipment as it is.

EU	Point	Equipment	Installed Date
P-API1	P-API1	Open API Separator	1968

EUG 59 – Covered API Separator Subject to NSPS Part 60 Subpart QQQ

EU	Point	Equipment	Installed Date
P-API2	P-API2	Covered API Separator	1978

A. The Covered API Separator (P-API2) shall comply with the primary or alternate standards for oil-water separators. [40 CFR 60.60.692-3(b) or 60.693-2(a)]

EUG 60 – Wastewater Systems Subject to NSPS Subpart QQQ and 40 CFR Part 63 Subpart CC in SRU, Diesel Hydrodesulfurization Area, Vacuum Unit 2 Area, GHDS Unit, Benfree Unit, and Hydrocracker Reformer

EU	Point	Equipment	VOC	
			lb/hr	TPY
EU-WW3	EU-WW3	SRU Closed Process Drains	0.88	3.83
		SRU Closed Junction Boxes	0.14	0.61
EU-WW4	EU-WW4	DHDU P-trap Drains	0.88	3.83
		DHDU Junction Boxes	0.14	0.61
EU-WW5	EU-WW5	Vac #2 P-trap Drains	0.88	3.83
		Vac #2 Junction Boxes	0.14	0.61
EU-WW6	EU-WW6	GHDS P-trap Drains	0.35	1.53
		GHDS Junction Boxes	0.14	0.61
EU-52WW	EU-52WW	Benfree Unit Drains	0.88	3.83
EU-53WW	EU-53WW	SMR WW Drains	0.21	0.92

A. The new wastewater handling equipment within the refinery is subject to NSPS, 40 CFR Part 60, Subpart QQQ and all affected equipment shall comply with all applicable requirements. [40 CFR 60, NSPS, Subpart QQQ]

1. § 60.692–1 Standards: General.
2. § 60.692–2 Standards: Individual drain systems.
3. § 60.692–3 Standards: Oil-water separators.
4. § 60.692–4 Standards: Aggregate facility.
5. § 60.692–5 Standards: Closed vent systems and control devices.
6. § 60.692–6 Standards: Delay of repair.
7. § 60.692–7 Standards: Delay of compliance.
8. § 60.693–1 Alternative standards for individual drain systems.
9. § 60.693–2 Alternative standards for oil-water separators.
10. § 60.695 Monitoring of operations.
11. § 60.696 Performance test methods and procedures and compliance provisions.
12. § 60.697 Recordkeeping requirements.
13. § 60.698 Reporting requirements.

EUG 61 – Wastewater Systems Subject to NSPS Subpart QQQ and 40 CFR Part 63 Subpart CC in Benfree Unit

EU	Point	Equipment	VOC	
			lb/hr	TPY
52-T01	52-T01	Benfree Unit Separator	0.85	3.73

A. The new wastewater handling equipment within the refinery is subject to NSPS, 40 CFR Part 60, Subpart QQQ and all affected equipment shall comply with all applicable requirements. [40 CFR 60, NSPS, Subpart QQQ]
1. § 60.692–1 Standards: General.
2. § 60.692–2 Standards: Individual drain systems.
3. § 60.692–3 Standards: Oil-water separators.
4. § 60.692–4 Standards: Aggregate facility.
5. § 60.692–5 Standards: Closed vent systems and control devices.
6. § 60.692–6 Standards: Delay of repair.
7. § 60.692–7 Standards: Delay of compliance.
8. § 60.693–1 Alternative standards for individual drain systems.
9. § 60.693–2 Alternative standards for oil-water separators.
10. § 60.695 Monitoring of operations.
11. § 60.696 Performance test methods and procedures and compliance provisions.
12. § 60.697 Recordkeeping requirements.
13. § 60.698 Reporting requirements.

EUG 64 – GHDS Oil/water Separator Subject to NSPS Subpart QQQ and 40 CFR Part 63 Subpart CC in Gasoline Hydrodesulfurization (GHDS) Unit

EU	Point	Description	VOC Emissions	
			lb/hr	TPY
EU-API3	P-API3	GHDS Oil-water Separator	2.99	1.11

A. The Covered Separator (P-API3) shall comply with the primary or alternate standards for oil-water separators. [40 CFR 60.692-3 or 60.693-2]

EUG 66 – Cooling Towers

EU	Point	Equipment	Installed Date
P-CWT1	P-CWT1	Crude Unit cooling tower	1958
P-CWT3	P-CWT3	FCCU cooling tower	1958
P-CWT5	P-CWT5	Alky Unit cooling tower	1968

A. These cooling towers shall comply with 40 CFR 63.654 and 40 CFR 63.655 upon the effective compliance date.

EUG 67 – Hydrocracker Cooling Tower

EU	Point	Equipment	VOC		PM	
			lb/hr	TPY	lb/hr	TPY
P-CWT4	P-CWT4	Hydrocracker Cooling Tower	0.34	1.47	0.11	0.48

A. These cooling towers shall comply with 40 CFR 63.654 and 40 CFR 63.655 upon the effective compliance date.

EUG 68 – GHDS Unit and Benfree Unit Cooling Towers Subject to 40 CFR 63 Subpart CC

EU	Point	Equipment	VOC		PM	
			lb/hr	TPY	lb/hr	TPY
EU-CWT6	P-CWT6	GHDS Cooling Tower	0.25	1.10	0.08	0.36
52-CT	52-CT	Benfree Unit Cooling Tower	0.05	0.22	0.13	0.58

A. The cooling towers are subject to 40 CFR Part 63 Subpart CC, Sec. 63.654 Heat exchange systems. [40 CFR 63.654]

EUG 80 – Non-gasoline Loading Racks

The following emissions are Insignificant Activities since emissions are less than 5 TPY.

EU	Point	Equipment	Installed Date
P-LR2T	P-LR2T	Gas oil truck unloading rack	1958
P-LT2R	P-LT2R	Gas oil rail unloading rack	1958
P-LR3T	P-LR3T	Solvent truck loading rack	1958
P-LT3R	P-LT3R	Solvent rail loading rack	1958
P-LR5T	P-LR5T	Asphalt truck loading rack	1960
P-LR5R	P-LR5R	Asphalt/slurry truck loading rack	1960
P-LR6T	P-LR6T	Slurry truck loading rack	1960

EUG 81 – New Non-gasoline Loading Rack

The following emissions are Insignificant Activities since emissions are less than 5 TPY.

EU	Point	Equipment	Installed Date
P-LR4T	P-LR4T	JP-8 truck loading rack	1996

<u>EUG 82 – Molten Sulfur Loading Racks</u>

EU	Point	Equipment	H_2S	
			lb/hr	TPY
P-SLRR	P-SLRR	Sulfur railcar loading rack	0.014	0.06
P-SLRT	P-SLRT	Sulfur truck loading rack	0.014	0.06

A. The H_2S content of discharges from this unit shall not exceed 4,000 ppm. [OAC 252:100-8-6(a)(1)]

B. At least once every calendar quarter, the permittee shall conduct testing of H_2S concentrations in discharges from this unit. Testing may be done using Draeger tubes or an equivalent method approved by Air Quality. [OAC 252:100-43]

<u>EUG 85 – FCCU Regenerator Subject to NSPS Subpart J and 40 CFR Part 63 Subpart UUU</u>

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-1ME258	FCCU regenerator	15.4	67.5	437.4	1916.	62.14	272.2	--	--	9.52	41.7

A. The FCCU catalyst regenerator is subject to NSPS Subpart J and shall comply with applicable standards for PM emissions. [40 CFR 60.103(a)]

B. The FCCU catalyst regenerator is subject to 40 CFR Part 63 Subpart UUU and small comply with applicable standards for CO emissions. [40 CFR 63.1565(a)(1)]

C. Continuous monitoring of CO emissions shall not be required for this unit. [40 CFR 63.1565(b)(1)(i)]

D. The FCCU catalyst regenerator shall comply with the provisions of 40 CFR Part 63, Subpart UUU. [40 CFR 63.1563(b)]

E. At least once per year, the permittee shall conduct performance testing as follows and furnish a written report to Air Quality. Testing shall be conducted while the FCCU is being operated at least 90% of permitted capacity. A sampling protocol and notification of testing date(s) shall be submitted at least 30 days in advance of commencement of testing. The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality: [OAC 252:100-43]

Method 1: Sample and Velocity Traverses for Stationary Sources.
Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate.
Method 3: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
Method 4: Moisture in Stack Gases.
Method 6 or 6C: Sulfur Dioxide Emissions from Stationary Sources
Method 7E: NOx Emissions from Stationary Sources

EUG 87 - SRU Tail Gas Incinerator Subject to NSPS Subpart J and 40 CFR Part 63 Subpart UUU

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	Lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
P-TGIS1	Sulfur Recovery Unit	0.22	1.00	18.90	82.77	3.01	13.20	0.17	0.73	11.90	52.12

A. P-TGIS1 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]

14. § 60.104 Standards for sulfur dioxide (SO_2) – (a)(2)(i);
15. § 60.105 Monitoring of operations – (a)(5)(i & ii) & (e)(4)(i);
16. § 60.106 Test methods and procedures – (a) & (f)(1 & 3).

B. P-TGIS1 is subject to National Emission Standards for Hazardous Air Pollutants (NESHAP), Subpart UUU and shall comply with all applicable provisions.

[40 CFR Part 63, Subpart UUU]

1. § 63.1568 What are my requirements for HAP emissions from sulfur recovery units? – (a)(1)(i), (b)(1, 2, 5, 6, & 7), & (c)(1 & 2);
2. § 63.1569 What are my requirements for HAP emissions from bypass lines? – (a)(1 & 3), (b)(1-4), & (c)(1 & 2);
3. § 63.1570 What are my general requirements for complying with this subpart? – (a) & (c-g);
4. 63.1571 How and when do I conduct a performance test or other initial compliance demonstration? – (a) & (b)(1-5);
5. 63.1572 What are my monitoring installation, operation, and maintenance requirements? – (a)(1-4) & (d)(1-2);
6. 63.1574 What notifications must I submit and when? – (a)(1-3), (c), (d), & (f)(1, 2(i), 2(ii), 2(viii), 2(ix), & 2(x));
7. 63.1575 What reports must I submit and when? – (a-h);
8. 63.1576 What records must I keep, in what form, and for how long? – (a), (b)(1, 3, 4, 5), & (d-i);
9. 63.1577 What parts of the General Provisions apply to me?

C. P-TGIS1 is subject to OAC 252:100-31-26 and shall comply with all applicable provisions.

[OAC 252:100-31-26]

1. Hydrogen sulfide (H_2S) from any new petroleum or natural gas process equipment shall be removed from the exhaust gas stream or it shall be oxidized to SO_2. H_2S emissions shall be reduced by 95% of the H_2S in the exhaust gas.

   [OAC 252:100-31-26(a)(1)]
2. Sulfur recovery plants operating in conjunction with any refinery process shall have the sulfur reduction efficiencies required below. [OAC 252:100-31-26(a)(2)(B)]
   i. When the sulfur content of the acid gas stream from the refinery process is greater than 5.0 LT/D but less than or equal to 150.0 LT/D, the required SO_2 emission reduction efficiency of the sulfur recovery plant shall be calculated using the following formula where Z is the minimum emission reduction efficiency required at all times and X is the sulfur feed rate expressed in LT/D of sulfur rounded to one decimal place: $Z = 92.34 (X^{0.00774})$

   [OAC 252:100-31-26(a)(2)(D)]

3. All new thermal devices for petroleum and natural gas processing facilities regulated under OAC 252:100-31-26(a)(1) shall have installed, calibrated, maintained, and operated an alarm system that will signal noncombustion of the gas.

[OAC 252:100-31-26(c)]

EUG 90 – Miscellaneous Insignificant Heaters

The following emission units are considered "Insignificant Activities" since emissions are less than 5 TPY.

Heater Designation	Location	MMBTUH
IH-1	Kyle House	0.10
IH-2	Main Office	0.375
IH-3	Webb House	0.10
IH-4	Laboratory	0.191
IH-5	Laboratory	0.15
IH-6	Laboratory	0.15
IH-7	Laboratory	0.15
IH-8	Laboratory	0.15
IH-9	Laboratory	0.191
IH-10	Electrical Shop	0.14
IH-11	Maintenance Office	0.15
IH-12	Maintenance Office	0.14
IH-13	East Shop	2.25
IH-14	West Shop	2.25

EUG 91 – Miscellaneous Reciprocating Engines

The following emissions are currently Insignificant Activities since emissions are less than 5 TPY.

Unit ID	Location	Unit Description	Unit Capacity
IE-1	Wastewater Plant	Caterpillar 3406B stormwater pump	300 HP
IE-2	Portable	Briggs/Stratton 195432 emergency generator	8 HP
IE-3	Portable	Generac 09441-2 emergency generator	5 HP
P-1183	Firewater Pump House	Cummins NT 855-F4 fire water pump	340 HP
P-1184	Firewater Pump House	Caterpillar 3406B fire water pump	375 HP
P-1185	Firewater Pump House	Cummins QSM11 fire water pump	400 HP

A. Upon the compliance date of NESHAPS Subpart ZZZZ, the owner/operator shall comply with all applicable requirements of the NESHAP: Reciprocating Internal Combustion Engines, Subpart ZZZZ, for each affected facility including but not limited to:

[40 CFR 63.6580 through 63.6675]

<u>What This Subpart Covers</u>
1. § 63.6580 What is the purpose of subpart ZZZZ?
2. § 63.6585 Am I subject to this subpart?
3. § 63.6590 What parts of my plant does this subpart cover?
4. § 63.6595 When do I have to comply with this subpart?

<u>Emission and Operating Limitations</u>
5. § 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

<u>General Compliance Requirements</u>
6. § 63.6605 What are my general requirements for complying with this subpart?

<u>Testing and Initial Compliance Requirements</u>
7. § 63.6625 What are my monitoring, installation, operation, and maintenance requirements?
8. § 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

<u>Continuous Compliance Requirements</u>
9. § 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

<u>Notifications, Reports, and Records</u>
10. § 63.6650 What reports must I submit and when?
11. § 63.6655 What records must I keep?
12. § 63.6660 In what form and how long must I keep my records?

<u>Other Requirements and Information</u>
13. § 63.6665 What parts of the General Provisions apply to me?
14. § 63.6670 Who implements and enforces this subpart?
15. § 63.6675 What definitions apply to this subpart?

<u>EUG 92 – Miscellaneous Insignificant Storage Tanks</u>

The following emissions are Insignificant Activities since emissions are less than 5 TPY.

Unit ID	Location	Capacity, Gallons	Contents
IT-1	Shop	2,000	gasoline
IT-2	Shop	1,000	diesel
IT-3	FCCU	1,975	lube oil
IT-4	Platformer	1,321	lube oil
IT-5	FCCU	1,000	lube oil
T-1417	Truck rack	2,000	fuel additive
IT-7	#2 Crude Unit	1,000	corrosion inhibitor
IT-8	#2 Crude Unit	750	corrosion inhibitor
IT-9	FCCU	1,000	corrosion inhibitor
IT-10	FCCU	1,000	corrosion inhibitor
IT-11	#1 Crude Unit	2,000	Embreak 2W157
IT-13	72 Manifold	250	Hi-Tec 4551
T-1414	Truck rack	6,000	fuel additive

Unit ID	Location	Capacity, Gallons	Contents
T-1416	Truck rack	6,000	fuel additive
IT-17	Crude Vacuum Unit	550	non-hydrocarbon
IT-18	Hydrocracker	3,171	Mystik Synguard
IT-19	ROSE Unit	2,325	Solvent cleaner
IT-20	Boilerhouse	400	non-hydrocarbon
IT-21	FCCU	1,600	corrosion inhibitor
IT-22	Lt. Oils Blender	765	corrosion inhibitor
IT-23	FCCU	750	corrosion inhibitor
IT-24	#1 Crude Unit	1,000	corrosion inhibitor
IT-25	#1 Crude Unit	750	corrosion inhibitor
IT-26	#2 Crude Unit	750	corrosion inhibitor
IT-27	#2 Crude Unit	1,000	corrosion inhibitor
IT-28	72 Manifold	250	fuel additive
IT-29	#1 Crude Unit	750	corrosion inhibitor
IT-30	#2 Crude Unit	1,000	corrosion inhibitor
IT-31	#2 Crude Unit	200	corrosion inhibitor
IT-32	Platformer	560	corrosion inhibitor
IT-33	Alky Unit	564	corrosion inhibitor
IT-34	FCCU	560	corrosion inhibitor
IT-35	72 Manifold	673	corrosion inhibitor
IT-36	FCCU	1,000	corrosion inhibitor
IT-37	Products Handling	560	corrosion inhibitor
T-1424	JP-8 Rack	2,000	fuel additive
T-1413	Truck rack	8,000	TFA-4906
IT-40	FCCU	6,428	TFA-4906
IT-41	#1 Crude Unit	2,000	anti-foulant
IT-42	#2 Crude Unit	1,000	anti-foulant
IT-43	FCCU	300	non-hydrocarbon
IT-44	Alky Unit	200	non-hydrocarbon
IT-45	#1 Crude Unit	1,000	non-hydrocarbon
T-1418	Truck rack	1,000	fuel additive
T-6092	72 Manifold	5,600	fuel additive
T-1426	Truck rack	1,000	fuel additive
T-1425	Near T-1475	1,000	fuel additive
T-1486	Near T-201	1,000	fuel additive
T-1476	Truck rack	7,400	diesel additive
P-T141	Diesel blending	8,000	Cetane
P-T1424	Diesel blending	2,000	diesel additive
P-T1425	Diesel blending	1,000	diesel additive
P-T1486	Diesel blending	1,000	diesel additive
P-T2001	Asphalt blending	21,000	oily waste water
P-T2002	Asphalt blending	4,200	oily waste water

<u>EUG 93 – Miscellaneous Insignificant Process Vents</u>

The following emissions are Insignificant Activities since emissions are less than 5 TPY.

Unit ID	Description
DAVENT	Reformer Deaerator Vent
BDVENT	Reformer Blowdown Vent
PSA Hydrogen	Reformer PSA Hydrogen Vent

2. The Crude Vacuum Unit Ejector process vents are subject to 40 CFR Part 63 Subpart CC and shall comply with all applicable requirements for vent stream HAP emissions control. Process vents shall either be vented to a flare meeting the requirements of 40 CFR Part 63 Subpart A, a control device which achieves 98% control efficiency of HAP emissions, a fuel gas system, or a device which reduces HAP emissions to 20 ppm or less. [40 CFR 63.643(a)]

3. In accordance with 40 CFR Part 61 Subpart FF, the permittee shall monitor the benzene content in wastewaters and shall report total benzene content (metric tons per year) annually to AQD. [40 CFR 61.357(c)]

4. The permittee shall be authorized to operate the facility continuously (24 hours per day, every day of the year). [OAC 252:100-8-6(a)]

5. The process heaters at the facility are subject to 40 CFR Part 63, Subpart DDDDD, and shall comply with applicable requirements as of the compliance date.

A. 63.7480 What is the purpose of this subpart?
B. 63.7485 Am I subject to this subpart?
C. 63.7490 What is the affected source of this subpart?
D. 63.7491 Are any boiler or process heaters not subject to this subpart?
E. 63.7495 When do I have to comply with this subpart?
F. 63.7499 What are the subcategories of boilers and process heaters?
G. 63.7500 What emission limits, work practice standards, and operating limits must I meet?
H. 63.7505 What are my general requirements for complying with this subpart?
I. 63.7506 Do any boilers or process heaters have limited requirements?
J. 63.7507 What are the health-based compliance alternatives for the hydrogen chloride (HCl) and total selected metals (TSM) standards?
K. 63.7510 What are my initial compliance requirements and by what date must I conduct them?
L. 63.7515 When must I conduct subsequent performance tests or fuel analyses?
M. 63.7520 What performance test and procedures must I use?
N. 63.7521 What fuel analyses and procedures must I use?
O. 63.7522 Can I use emission averaging to comply with this subpart?
P. 63.7525 What are my monitoring, installation, operation and maintenance requirements?
Q. 63.7530 How do I demonstrate initial compliance with the emissions limits and work practice standards?

R. 63.7535 How do I monitor and collect data to demonstrate continuous compliance?
S. 64.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?
T. 63.7541 How do I demonstrate continuous compliance under the emission averaging provisions?
U. 63.7545 What notifications must I submit and when?
V. 63.7550 What reports must I submit and when?
W. 63.7555 What records must I keep?
X. 63.7560 In what form and how long must I keep my records?
Y. 63.7565 What parts of the General Provisions apply to me?
Z. 63.7570 Who implements and enforces this subpart?
AA. 63.7575 What definitions apply to this subpart?

6. The following records shall be maintained on location for inspection by ODEQ regulatory personnel. The required records shall be retained either in printed hard-copy or electronically for a period of at least five years following the date of recording. [OAC 252:100-8-6(a)(3)(b)]

A. Sulfur content of gas fuels used in EUGs No. 37, 38, 39, 40, 41, 42, 44, and 46 (continuous when operating).
B. Opacity of FCCU catalyst regenerator emissions (continuous when operating).
C. Vapor pressures and throughputs of all tanks listed in EUGs No. 3, 5, 7, 9, 10, 12, 13, 14, 16, and 17 (monthly and 12-month rolling totals).
D. Operating temperatures of the Asphalt Unit thermal oxidizer (continuous when operating).
E. Seal gap inspections for floating roof tanks subject to NSPS Subpart K, Subpart Ka, or Subpart Kb; or 40 CFR Part 63 Subpart CC.
F. Inspection of water seals on drains on systems in EUGs 57 (CCR Platformer), 60 (SRU & DHDU), and 61 (No. 2 Vacuum Unit and Benfree Unit).
G. Records as required by 40 CFR Part 63 Subpart CC and Subpart R for gasoline loading terminals:
    1. VOC concentrations in discharges
    2. vapor tightness of tank trucks
    3. leak testing of valves, meters, etc.
H. Records as required by NSPS Subparts GGG and GGGa and/or 40 CFR Part 63 Subpart CC of leak detection and repair for the Alkylation Unit Area, Platformer Unit Area, No. 1 Crude/Vacuum Unit Area, No. 2 Crude/Vacuum Unit Area, Diesel Hydrodesulfurization Unit Area, Bulk Gasoline Terminal Area, FCCU Unit Area, Hydrocracker Unit Area, Asphalt Unit Area, Amine/SWS/SRU/TGTU Area, Steam/Utilities/Flare System Area, Gasoline Hydrodesulfurization Unit, and Benfree Unit.
I. Records of annual benzene content in wastewater as required by 40 CFR 61, Subpart FF.
J. Records of testing of H_2S emissions from Asphalt Unit Sulfatreat unit (weekly), Sulfur loading racks (quarterly), and molten sulfur pit (quarterly).
K. Records as required by 40 CFR Part 60, Subpart QQQ.
L. Records as required by 40 CFR Part 63 Subpart UUU.
M. Records as required by NSPS Subparts J and Ja.

N. Records as required by 40 CFR Part 63 Subpart DDDDD.
O. Records as required by 40 CFR Part 63 Subpart LLLLL.
P. Records as required by 40 CFR Part 60.48c(g) of fuels used in 40-H1101, 40-WPB1, and 40-HPB1 (monthly).
Q. Per OAC 252:100-8-36.2-(c), records shall be kept comparing actual emissions from units in the Gasoline Hydrodesulfurization Unit project with projected actual emissions showing that net emissions changes are less than PSD levels of significance. Records shall be kept for calendar years up to and including 2015.
R. Records as required by 40 CFR Part 63, Subpart ZZZZ
S. Records for Heat Exchanger Systems required by 40 CFR 63 Subpart CC.
T. Records of natural gas feed to the Hydrogen Plant Reformer (monthly and 12-month rolling totals).

7. The following records shall be maintained on site to verify insignificant activities.

[OAC 252:8-6(a)(3)(b)]

A. Hours of operation of stationary reciprocating engines burning natural, gasoline, aircraft fuels, or diesel fuel which are either used exclusively for emergency power generations or for peaking power service not exceeding 500 hours per year (monthly and 12-month rolling total)
B. Throughput at fuel storage/dispensing equipment operated solely for facility owned vehicles (monthly, averaged over a 30-day period)
C. Contents and vapor pressures of storage tanks in EUG-90
D. Drum/barrel washing operation throughput.
E. Emissions from miscellaneous process vents in EUG-93.

8. No later than 30 days after each anniversary date of the issuance of the initial Part 70 operating permit (July 8, 2002), the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit.

[OAC 252:100-8-6 (c)(5)(a)&(d)]

9. The Permit Shield (Standard Conditions, Section VI) is extended to the following requirements that have been determined to be inapplicable to this facility.

[OAC 252:100-8-6(d)(2)]

A.	OAC 252:100-11	Alternative Emissions Reduction
B.	OAC 252:100-15	Mobile Sources
C.	OAC 252:100-17	Incinerators
D.	OAC 252:100-23	Cotton Gins
E.	OAC 252:100-24	Grain Elevators
F.	OAC 252:100-39	Nonattainment Areas
G.	OAC 252:100-47	Landfills
H.	40 CFR Part 60, Subpart Db	Steam Generating Units (100-250 MMBTUH)
I.	40 CFR Part 60, Subpart XX	Gasoline Loading Terminals
J.	40 CFR Parts 72, 73, 74, 75, and 76	Acid Rain

10. Compliance Plans

Category	**Activities**	**Deadline**
Compliance plan for flare (monitoring & fuel gas requirements)	1. Respondent completed a 2-phase process safety study of its flare systems for Occupational Safety and Health Administration (OSHA) purposes in May 2009. Phase I included unit mass balances to develop baseline process data for simulation of flaring scenarios. Phase II recommended solutions to problems identified in Phase I. Issues included flare system loading and flow, flare knockout drums, flare header low points, and process safety valves (PSVs), including atmospheric PSVs which will be connected to the flare system. Issues have been prioritized and implementation is underway, with projects included in the 2012 turnaround work scope. These issues will be resolved by completion of the 2012 turnaround or December 31, 2012, whichever is later, with the exception of low priority PSV issues which will be resolved by completion of the 2016 turnaround or December 31, 2016, whichever is later. While this work is primarily for safety concerns, it may result in reduced emissions during malfunctions which are exempt from NSPS J and Ja. As part of the February 7, 2013 Progress Report, WRC will provide a list of the items completed as provided to OSHA and any issues that will be resolved during the 2016 turnaround.	Completed
	2. Review and prioritize flare system connections and control systems for flaring reduction opportunities and develop engineering solutions and an implementation schedule. WRC will submit the implementation schedule to DEQ as part of the August 7, 2013 Progress Report.	Completed
	3. Implement solutions identified from task 2 above.	December 31, 2016
	4. Install flare fuel gas continuous emission monitoring system CEMS (& fuel gas flow meters, if required) per 40 CFR 60 Ja requirements on Peabody, South, and Hydrocracker flares. The Backup flare (emission unit group ("EUG") 47)) is on a water seal system downstream from the Peabody flare; therefore no additional monitoring will be installed on this flare.	December 31, 2016

Category	Activities	Deadline
LDAR Compliance Plan	1. A retagging effort began in March 2010 and will be completed by December 31, 2011. This effort will produce an updated master equipment list (MEL) based on updated P&IDs. Tanks on the MEL will be kept separate from process units, although the MEL will also show what process unit a tank is associated with, when applicable.	Completed
	2. Develop and implement an improved internal notification and tracking system for streamlined repair procedures and repair deadlines.	Completed
Compliance plan for sulfur-related issues (FGCDs & Peabody Flare)	1. TKI to commence construction of ammonium thiosulfate (ATS) plant as redundant sulfur processing unit (60 ltpd capacity).	Completed
	2. Complete H_2S tie-ins to ATS plant.	Completed
	3. ATS plant startup.	Completed
Vapor recovery Unit (VRU) compliance plan	1. Develop and implement a system that complies with 40 C.F.R. Part 63, Subpart CC, by June 30, 2013.	June 30, 2013
Benzene compliance plan	1. Respondent will conduct a one-time audit of benzene wastes to ensure compliance with 40 C.F.R. Part 61, Subpart FF by resampling streams which contribute significantly to TAB over an 18-month period beginning January 2013.	Completed
	2. Respondent will identify the streams to be sampled and include them in the August 7, 2013 Progress Report.	Completed
	3. Sampling and analysis will be completed by June 30, 2014.	June 30, 2014
	4. A report including the streams sampled and a re-calculation of the facility's TAB will be submitted with the August 7, 2014 Progress Report.	August 7, 2014
FCCU compliance plan	1. Will replace flue gas steam generator.	Completed

Category	Activities	Deadline
Permit revisions	1. Respondent will submit a revised Title V Renewal and/or Modification Application by June 30, 2012. The permit application will include: a. updated component count estimates for fugitive emissions units b. a new proposed permit limit for EUG 15 and EUG 16 based on data gathered upstream of the Sulfatreat unit c. a revised CCR regenerator limit consistent with the test results generated pursuant to provision 2 in the Miscellaneous Items Compliance Plan.	Completed

11. The facility shall apply for a modified operating permit within 180 days of start-up of the new hydrogen plant.

12. Within 180 days of start-up of the new reformer, the permittee shall conduct performance testing of the new reformer as follows and furnish a written report to Air Quality. Testing shall be conducted while the reformer is being operated at least 90% of permitted hourly capacity. A sampling protocol and notification of testing date(s) shall be submitted at least 30 days in advance of commencement of testing. The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality: [OAC 252:100-43]

Method 1:	Sample and Velocity Traverses for Stationary Sources.
Method 2:	Determination of Stack Gas Velocity and Volumetric Flow Rate.
Method 3:	Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
Method 4:	Moisture in Stack Gases.
Method 7E:	NOx Emissions from Stationary Sources
Method 10:	CO Emissions from Stationary Sources
Method 25A:	Non-Methane Organic Emissions from Stationary Sources

If a CEM is installed to measure NOx emissions, testing by Method 7E is sufficient as CEM certification testing.

Ms. Sidney Cabbiness
Environmental Manager
Wynnewood Refining Company, LLC
906 S. Powell
Wynnewood, OK 73098

SUBJECT: Permit No. **2007-026-C (M-5)(PSD)**
Wynnewood Refinery
Garvin County, Oklahoma

Dear Ms. Cabbiness:

Enclosed is the permit authorizing construction of the referenced facility. Please note that this permit is issued subject to standard and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emissions inventory for this facility. An emissions inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form or submittal process should be referred to the Emissions Inventory Staff at 405-702-4100.

Thank you for your cooperation in this matter. If we can be of further service, please contact our office at (405) 702-4198.

Sincerely,

David S. Schutz, P.E.
New Source Permits Section
AIR QUALITY DIVISION

enclosure

PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 N. ROBINSON STREET, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 2007-026-C (M-5)(PSD)

Wynnewood Refining Company, LLC

having complied with the requirements of the law, is hereby granted permission to construct a hydrogen plant at a petroleum refinery at Wynnewood, Garvin County, Oklahoma subject to standard conditions dated July 21, 2009, and specific conditions, both attached

This permit shall expire 18 months from the date below, except as authorized under Section VIII of the Standard Conditions.

Division Director, **Date**

Air Quality Division

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(July 21, 2009)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.
[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:
(1) the date, place and time of sampling or measurement;
(2) the date or dates analyses were performed;
(3) the company or entity which performed the analyses;
(4) the analytical techniques or methods used;
(5) the results of such analyses; and
(6) the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report. [OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions. [OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act. [OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants ("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.

[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM_{10}). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.

[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.

[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.
[OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.

[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.

[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.

[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.

[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
(4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d). [OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.

[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that: [OAC 252:100-8-6 (e)(2)]

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.

[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.
[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]

(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]

(a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
(b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
(c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
(d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and

the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and
(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term “MVAC” as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;
(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;
(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;
(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).
(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).
(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).
(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.
(6) The DEQ complies with 40 C.F.R. § 70.8(d).
(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).
(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.

(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]